PAC-E

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

RECEIVED
2020 MAY 21 AM 10: 22
IDAHO PUBLIC
UTILITIES COMMISSION

1407 W. North Temple, Suite 330
Salt Lake City, Utah 84116

May 19, 2020

VIA OVERNIGHT DELIVERY

Idaho Public Utilities Commission
11331 W Chinden Blvd.
Building 8 Suite 201A
Boise, ID 83714

Attention: Diane Hanian
Commission Secretary

Re: Annual Idaho Form 1 Report – 2019

Rocky Mountain Power, a division of PacifiCorp, hereby submits for filing an original and seven (7) copies of the Idaho Public Utilities Commission Annual State Form 1 report for 2019. This is being provided with PacifiCorp's annual FERC Form 1.

It is respectively requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@PacifiCorp.com

By Fax: (503) 813-6060

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

Any informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at 801-220-2963.

Sincerely,

Joelle Steward

Joelle Steward
Vice President, Regulation

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM NO. 1
FOR
MULTI-STATE ELECTRIC COMPANIES

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Data provided in this report is consistent with the unadjusted data reflected in the company's Results of Operations in the Idaho general rate case, which will be filed with the Idaho Public Utilities Commission on June 1, 2020. For further information regarding Idaho's 2019 financial results, refer to the Idaho general rate case.

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) X An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 19, 2020	Year of Report Dec. 31, 2019

STATE OF IDAHO STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	ACCOUNT (a)	(Ref) Page No. (b)	ELECTRIC UTILITY Current Year (c)	 Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	298,763,227	311,215,580
3	Operating Expenses			
4	Operation Expenses (401)	3-6	148,465,404	155,045,764
5	Maintenance Expenses (402)	3-6	20,256,417	23,414,617
6	Depreciation Expenses (403) (1)	7	40,903,100	41,826,626
7	Amort. & Depl. of Utility Plant (404-405)	7	2,688,697	2,656,503
8	Amort. of Utility Plant Acq. Adj (406)		282,644	296,455
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		-	-
10	Amort. of Conversion Expenses (407)		-	-
11	Taxes other Than Income Taxes (408.1) (2)	8	9,389,124	9,849,439
12	Income Taxes - Federal (409.1)		11,126,860	13,328,069
13	- Other (409.1)		2,893,193	3,704,835
14	Provision for Deferred Income Taxes (410.1)		14,858,331	11,297,703
15	Provision for Deferred Income Taxes - Cr. (411.1)		(18,512,483)	(16,807,498)
16	Investment Tax Credit Adj. - Net (411.4)		(312,920)	(372,891)
17	(Gain)/Loss from Disp. of Utility Plant (411.6, 411.7, 421)		(211,561)	(59,227)
18	Gains from Disp. Of Allowances (411.8)		(11)	(12)
19	TOTAL Utility Operating Expenses *(Enter Total of Lines 4 thru 18)*		231,826,795	244,180,383
20	Net Utility Operating Income *(Enter Total of line 2 less 19)*		66,936,432	67,035,197

(1) Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress.

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp dba Rocky Mountain Power	(1) _X_ An Original (2) __ A resubmission	(Mo, Da, Yr) May 19, 2020	Dec. 31, 2019

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous period (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote).
5. See page 108-109 of FERC Form No. 1, Important Changes During Period, for important new territory added and important rate increases or decreases.
6. For lines 2,4,5,6, and 7 see page 304 of FERC Form No. 1 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES		MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH	
		Amount for Year (a)	Amount for Previous Year (c)	Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)
1	Sales of Electricity						
2	(440) Residential Sales	78,861,152	75,609,572	735,158	703,239	66,558	64,774
3	(442) Commercial and Industrial Sales						
4	Small (or Commercial) (See Instr. 4)	43,891,041	43,737,331	512,559	511,119	9,175	8,964
5	Large (or Industrial) (See Instr. 4)	155,745,653	166,377,983	2,235,057	2,426,431	5,653	5,629
6	(444) Public Street and Highway Lighting	511,533	502,969	2,702	2,645	115	117
7	(445) Other Sales to Public Authorities	-	-	-	-	-	-
8	(446) Sales to Railroads and Railways	-	-	-	-	-	-
9	(448) Interdepartmental Sales	-	-	-	-	-	-
10	TOTAL Sales to Ultimate Consumers	279,009,379	286,227,855	3,485,476	3,643,434	81,501	79,484
11	(447) Sales for Resale	10,499,006	14,860,573	(1)	(1)	(1)	(1)
12	TOTAL Sales of Electricity	289,508,385	301,088,428	3,485,476	3,643,434	81,501	79,484
13	(Less) (449.1) Provision for Rate Refunds	-	-	-	-	-	-
14	TOTAL Revenue Net of Prov. For Refunds	289,508,385	301,088,428	3,485,476	3,643,434	81,501	79,484
15	Other Operating Revenues						
16	(450) Forfeited Discounts	334,885	392,368				
17	(451) Miscellaneous Service Revenues	91,047	85,084				
18	(453) Sale of Water and Water Power	3,172	3,386				
19	(454) Rent from Electric Property	655,225	627,352				
20	(455) Interdepartmental Rents	-	-				
21	(456) Other Electric Revenues	8,170,513	9,018,962				
22							
23	TOTAL Other Operating Revenues	9,254,842	10,127,152				
24	TOTAL Electric Operating Revenues	298,763,227	311,215,580				

(1) For a complete list of the number of customers and Megawatt hours sold on a total company basis see pages 310-311 - Sales for Resale of the 2019 FERC Form No. 1.

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ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,053,665	1,106,501
5	(501) Fuel	47,745,478	51,813,402
6	(502) Steam Expenses	4,743,637	5,000,469
7	(503) Steam from Other Sources	315,452	307,616
8	(Less) (504) Steam Transferred - Cr.	-	-
9	(505) Electric Expenses	90,589	95,379
10	(506) Miscellaneous Steam Power Expenses	1,598,531	1,511,166
11	(507) Rents	29,110	30,295
12	TOTAL Operation (Enter Total of lines 4 thru 11)	55,576,462	59,864,828
13	Maintenance		
14	(510) Maintenance Supervision and Engineering	431,127	495,217
15	(511) Maintenance of Structures	1,632,341	1,670,850
16	(512) Maintenance of Boiler Plant	5,263,249	5,843,098
17	(513) Maintenance of Electric Plant	2,335,427	2,509,582
18	(514) Maintenance of Miscellaneous Steam Plant	612,214	602,716
19	TOTAL Maintenance (Enter Total of lines 14 thru 18)	10,274,358	11,121,463
20	TOTAL Power Production Expenses - Steam Power (Enter Total of lines 12 & 19)	65,850,820	70,986,291
21	B. Nuclear Power Generation		
22	Operation		
23	(517) Operation Supervision and Engineering	-	-
24	(518) Fuel	-	-
25	(519) Coolants and Water	-	-
26	(520) Steam Expenses	-	-
27	(521) Steam from Other Sources	-	-
28	(Less) (522) Steam Transferred - Cr.	-	-
29	(523) Electric Expenses	-	-
30	(524) Miscellaneous Nuclear Power Expenses	-	-
31	(525) Rents	-	-
32	TOTAL Operation (Enter Total of lines 23 thru 31)	-	-
33	Maintenance		
34	(528) Maintenance Supervision and Engineering	-	-
35	(529) Maintenance of Structures	-	-
36	(530) Maintenance of Reactor Plant Equipment	-	-
37	(531) Maintenance of Electric Plant	-	-
38	(532) Maintenance of Miscellaneous Nuclear Plant	-	-
39	TOTAL Maintenance (Enter Total of lines 34 thru 38)	-	-
40	TOTAL Power Production Expenses - Nuclear Power (Enter Total of lines 32 & 39)	-	-
41	C. Hydraulic Power Generation		
42	Operation		
43	(535) Operation Supervision and Engineering	559,356	525,686
44	(536) Water for Power	2,139	2,379
45	(537) Hydraulic Expenses	240,778	281,394
46	(538) Electric Expenses	-	-
47	(539) Miscellaneous Hydraulic Power Generation Expenses	1,184,501	1,150,134
48	(540) Rents	100,275	75,780
49	TOTAL Operation (Enter Total of lines 43 thru 48)	2,087,049	2,035,373

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ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	23	29
53	(542) Maintenance of Structures	38,228	44,458
54	(543) Maintenance of Reservoirs, Dams, and Waterways	104,645	88,434
55	(544) Maintenance of Electric Plant	118,998	104,353
56	(545) Maintenance of Miscellaneous Hydraulic Plant	258,795	240,598
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	520,689	477,872
58	TOTAL Power Production Expenses - Hydraulic Power (Enter Total of lines 49 & 57)	2,607,738	2,513,245
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	21,032	17,707
62	(547) Fuel	18,275,033	15,603,255
63	(548) Generation Expenses	1,019,903	1,092,226
64	(549) Miscellaneous Other Power Generation Expenses	455,878	311,294
65	(550) Rents	168,480	249,926
66	TOTAL Operation (Enter Total of lines 61 thru 65)	19,940,326	17,274,408
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	-	-
69	(552) Maintenance of Structures	140,354	272,609
70	(553) Maintenance of Generation and Electric Plant	723,469	1,101,066
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	177,191	193,095
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	1,041,014	1,566,770
73	TOTAL Power Production Expenses - Other Power (Enter Total of lines 66 & 72)	20,981,340	18,841,178
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	40,093,922	43,924,705
76	(556) System Control and Load Dispatching	45,552	75,113
77	(557) Other Expenses **(1)**	6,797,525	7,002,440
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	46,936,999	51,002,258
79	TOTAL Power Production Expenses - (Enter Total of lines 20, 40, 58, 73 and 78)	136,376,897	143,342,972
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	435,102	419,901
83	(561) Load Dispatching	1,206,737	1,233,382
84	(562) Station Expenses	184,669	179,919
85	(563) Overhead Line Expenses	64,407	53,602
86	(564) Underground Line Expenses	-	-
87	(565) Transmission of Electricity by Others	8,650,055	8,369,141
88	(566) Miscellaneous Transmission Expenses	177,709	177,269
89	(567) Rents	132,649	132,576
90	TOTAL Operation (Enter Total of lines 82 thru 89)	10,851,328	10,565,790
91	Maintenance		
92	(568) Maintenance Supervision and Engineering	77,103	89,563
93	(569) Maintenance of Structures	342,147	382,730
94	(570) Maintenance of Station Equipment	697,326	743,056
95	(571) Maintenance of Overhead Lines	957,687	1,001,154
96	(572) Maintenance of Underground Lines	3,401	5,072
97	(573) Maintenance of Miscellaneous Transmission Plant	9,072	13,774
98	TOTAL Maintenance (Enter Total of lines 92 thru 97)	2,086,736	2,235,349
99	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	12,938,064	12,801,139
100	3. DISTRIBUTION EXPENSES		
101	Operation		
102	(580) Operation Supervision and Engineering	438,136	436,443
103	(581) Load Dispatching	607,671	573,951

(1) The Idaho amounts in Account 557 Other expenses are $5,961,983 for the current year and $6,016,898 for the previous year. However, the amount for this year has been increased by $835,542 because of the impact of the 2020 Protocol Adjustment, while in the prior year it was increased by 985,542 because of the impact of the 2017 Protocol Adjustment.

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ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(582) Station Expenses	472,115	453,365
106	(583) Overhead Line Expenses	313,774	429,560
107	(584) Underground Line Expenses	-	-
108	(585) Street Lighting and Signal System Expenses	11,201	12,318
109	(586) Meter Expenses	183,938	199,955
110	(587) Customer Installations Expenses	886,970	969,859
111	(588) Miscellaneous Distribution Expenses	(977)	39,619
112	(589) Rents	34,956	40,588
113	TOTAL Operation (Enter Total of lines 102 thru 112)	2,947,784	3,155,658
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	333,798	245,783
116	(591) Maintenance of Structures	148,372	116,697
117	(592) Maintenance of Station Equipment	507,870	327,807
118	(593) Maintenance of Overhead Lines	2,587,944	4,697,065
119	(594) Maintenance of Underground Lines	902,167	759,910
120	(595) Maintenance of Line Transformers	50,126	48,446
121	(596) Maintenance of Street Lighting and Signal Systems	91,042	102,493
122	(597) Maintenance of Meters	36,291	16,860
123	(598) Maintenance of Miscellaneous Distribution Plant	287,462	319,595
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	4,945,072	6,634,656
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	7,892,856	9,790,314
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	95,981	103,732
129	(902) Meter Reading Expenses	2,171,132	2,057,782
130	(903) Customer Records and Collection Expenses	1,989,916	2,168,720
131	(904) Uncollectible Accounts	657,699	433,211
132	(905) Miscellaneous Customer Accounts Expenses	756	642
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132)	4,915,484	4,764,087
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	283	4,925
137	(908) Customer Assistance Expenses	132,712	103,768
138	(909) Informational and Instructional Expenses	266,394	235,807
139	(910) Miscellaneous Customer Service and Informational Expenses	190	1,732
140	TOTAL Cust. Service and Informational Exp. (Enter Total of lines 136 thru 139)	399,579	346,232
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	-	-
145	(913) Advertising Expenses	-	-
146	(916) Miscellaneous Sales Expenses	-	-
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	-	-
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	4,377,494	4,280,871
151	(921) Office Supplies and Expense	560,397	598,608
152	(Less) (922) Administrative Expenses Transferred - Cr.	(1,976,601)	(1,890,263)
153	(923) Outside Services Employee	1,164,399	1,083,680
154	(924) Property Insurance	384,332	421,773
155	(925) Injuries and Damages	357,318	962,344
156	(926) Employee Pensions and Benefits **(1)**	5,817,860	6,767,804
157			

(1) Pensions and benefits expense is associated with labor and generally charged to operations and maintenance expense and construction work in progress.

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ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - IDAHO

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
157	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
158	(927) Franchise Requirements	-	-
159	(928) Regulatory Commission Expenses	1,339,610	1,161,503
160	(929) Duplicate Charges - Cr.	(7,468,193)	(7,619,742)
161	(930.1) General Advertising Expenses	3,145	34
162	(930.2) Miscellaneous General Expenses	125,122	129,277
163	(931) Rents	125,510	141,241
164	TOTAL Operation (Enter Total of lines 150 thru 163)	4,810,393	6,037,130
165	Maintenance		
166	(935) Maintenance of General Plant	1,388,548	1,378,507
167	TOTAL Administrative and General Expenses (Enter Total of lines 164 & 166)	6,198,941	7,415,637
168	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 79, 99, 125, 133, 140, 147, and 167)	168,721,821	178,460,381

SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Line No.	Functional Classifications (a)	Operation (b)	Maintenance (c)	Total (d)
169	Power Production Expenses			
170	Electric Generation:			
171	Steam Power	55,576,462	10,274,358	65,850,820
172	Nuclear Power	-	-	-
173	Hydraulic -Conventional	2,087,049	520,689	2,607,738
174	Other Power Generation	19,940,326	1,041,014	20,981,340
175	Other Power Supply Expenses	46,936,999	-	46,936,999
176	Total Power Production Expenses	124,540,836	11,836,061	136,376,897
177	Transmission Expenses	10,851,328	2,086,736	12,938,064
178	Distribution Expenses	2,947,784	4,945,072	7,892,856
179	Customer Accounts Expenses	4,915,484	-	4,915,484
180	Customer Service and Informational Expenses	399,579	-	399,579
181	Sales Expenses	-	-	-
182	Adm. and General Expenses	4,810,393	1,388,548	6,198,941
183	Total Electric Operation and Maintenance Expenses	148,465,404	20,256,417	168,721,821

STATE OF IDAHO - ALLOCATED

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _x_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 19, 2020	Year of Report Dec. 31, 2019

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition adjustments)

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) [(1)] (b)	Amortization of Limited-Term Electric Plant (Acct. 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	-	2,654,017	-	2,654,017
2	Steam Production Plant	14,512,632	-	-	14,512,632
3	Nuclear Production Plant	-	-	-	-
4	Hydraulic Production Plant - Conventional	2,454,040	18,425	-	2,472,465
5	Hydraulic Production Plant - Pumped Storage	-	-	-	-
6	Other Production Plant	7,581,927	-	-	7,581,927
7	Transmission Plant	6,650,467	-	-	6,650,467
8	Distribution Plant	7,262,954	-	-	7,262,954
9	General Plant	2,441,080	16,255	-	2,457,335
10	Common Plant - Electric	-	-	-	-
11	TOTAL	40,903,100	2,688,697	-	43,591,797

(1) Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress.

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STATE OF IDAHO - ALLOCATED
TAXES, OTHER THAN INCOME TAXES
ACCOUNT 408.1 [(1)]

	KIND OF TAX	AMOUNT
1	Property	8,505,483
2	Other	883,641
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20	Total (Must agree with page 1, line 11.)	9,389,124

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp dba Rocky Mountain Power	(1) X An Original (2) __ A resubmission	(Mo, Da, Yr) May 19, 2020	Dec. 31, 2019

NON-UTILITILY PROPERTY (ACCOUNT 121)

	Location Description	Description	Beginning Balance (c)	Acquistion (d)	Retirement (e)	Transfer (f)	Balance at End of Year (g)
1	IDAHO FALLS POLE TREATING PLANT	Fee Land	54,317				54,317
2	MALAD PLANT SITE AND WATER RIGHTS	Land Rights	33				33
3	GEORGETOWN PLANT LAND	Fee Land	110				110
4	LAVA DEVELOPMENT	Land Rights	1,274				1,274
5	MENAN SUBSTATION SITE	Fee Land	55				55
6	UCON SITE - CATERCORNER TO UCON SUBSTATION	Fee Land	27				27
7	OLD DUBOIS SUBSTATION SITE	Fee Land	75				75
8	EAST RIVER SUBSTATION SITE	Fee Land	13,742				13,742
9	NORTH MONTEVIEW SUBSTATION SITE	Fee Land	328				328
10	MONTEVIEW SUBSTATION SITE	Fee Land	618				618
11	MUD LAKE SERVICE CENTER	Fee Land	17,915				17,915
12	LAVA SUBSTATION AND SERVICE CENTER	Fee Land	382				382
13	Total Non-Utility Property		88,876	-	-	-	88,876

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	**UTILITY PLANT**		
2	In Service		
3	Plant In Service (Classified)	1,609,735,369	1,645,966,883
4	Property Under Capital Lease **(1)**	-	-
5	Plant Purchased or Sold	-	-
6	Completed Construction not Classified	13,990,267	14,289,130
7	Experimental Plant Unclassified	-	-
8	Total (Enter Total of Lines 3 through 7)	1,623,725,636	1,660,256,013
9	Leased To Others	-	-
10	Held for Future Use	743,669	780,006
11	Construction Work In Process **(2)**	-	-
12	Acquisition Adjustments	8,553,673	8,971,626
13	Total Utility Plant (Enter Total of Lines 8 through 12)	1,633,022,978	1,670,007,645
14	Accumulated Provision for Depreciation, Amortization & Depletion	583,411,736	626,334,125
15	Net Utility Plant (Enter Total of Line 13 less Line 14)	1,049,611,242	1,043,673,520
16	**DETAIL OF ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION AND DEPLETION**		
17	In Service		
18	Depreciation	538,669,948	582,574,935
19	Amortization/Depletion of Producing Natural Gas Land And Land Rights	-	-
20	Amortization of Underground Storage Land and Land Rights	-	-
21	Amortization of Other Utility Plant	37,009,557	35,945,599
22	Total In Service (Enter Total of Lines 18 through 21)	575,679,505	618,520,534
23	Leased To Others		
24	Depreciation	-	-
25	Amortization And Depletion	-	-
26	Total Leased to Others (Enter Total of Lines 24 and 25)	-	-
27	Held for Future Use		
28	Depreciation	-	-
29	Amortization	-	-
30	Total Held for Future Use (Enter Total of Lines 28 and 29)	-	-
31	Abandonment of Leases (Natural Gas)	-	-
32	Accumulated Provision for Asset Acquisition Adjustment	7,732,231	7,813,591
33	Total Accumulated Provisions (Should Agree With Line 14 above) (Enter Total of Lines 22, 26, 30, 31 and 32)	583,411,736	626,334,125
34			

(1) Capitalized lease assets are not included in rate base; they are included in operating expense as rent expense.

(2) Construction Work In Process ("CWIP") is not included in rate base and it is not assigned allocation factors until it goes into service. On a total company basis, CWIP was $2,002,448,524 at December 31, 2019.

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _X_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 19, 2020	Year of Report Dec. 31, 2019

ELECTRIC PLANT IN SERVICE - STATE OF IDAHO (ALLOCATED)

(In addition to Account 101, Electric Plant In Service (Classified), this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

Line No.	Account (a)	Beginning Balance (b)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT		
2	(301) Organization	-	-
3	(302) Franchises and Consents	13,140,328	12,558,231
4	(303) Miscellaneous Intangible Plant	43,314,263	44,786,124
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	56,454,591	57,344,355
6	2. PRODUCTION PLANT		
7	A Steam Production Plant		
8	(310) Land and Land Rights	5,765,332	5,496,677
9	(311) Structures and Improvements	64,108,123	62,095,207
10	(312) Boiler Plant Equipment	288,358,237	273,912,728
11	(313) Engines and Engine Driven Generators	-	-
12	(314) Turbogenerator Units	61,889,243	59,332,914
13	(315) Accessory Electric Equipment	30,234,918	28,928,131
14	(316) Misc. Power Plant Equipment	2,022,561	1,995,931
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	452,378,414	431,761,588
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	-	-
18	(321) Structures and Improvements	-	-
19	(322) Reactor Plant Equipment	-	-
20	(323) Turbogenerator Units	-	-
21	(324) Accessory Electric Equipment	-	-
22	(325) Misc. Power Plant Equipment	-	-
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	-	-
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	2,251,829	2,146,926
26	(331) Structures and Improvements	17,115,819	16,485,450
27	(332) Reservoirs, Dams, and Waterways	31,609,560	30,497,570
28	(333) Water Wheels, Turbines, and Generators	8,487,266	8,387,526
29	(334) Accessory Electric Equipment	5,221,187	5,038,180
30	(335) Misc. Power Plant Equipment	146,681	151,171
31	(336) Roads, Railroads, and Bridges	1,523,981	1,474,512
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	66,356,323	64,181,335
33	D. Other Production Plant		
34	(340) Land and Land Rights	2,812,170	3,007,808
35	(341) Structures and Improvements	14,157,209	13,579,128
36	(342) Fuel Holders, Products, and Accessories	1,003,663	956,906
37	(343) Prime Movers	181,335,937	165,249,468
38	(344) Generators	29,475,202	29,446,063
39	(345) Accessory Electric Equipment	20,299,717	19,171,041
40	(346) Misc. Power Plant Equipment	987,300	941,306
41	TOTAL Other Production Plant (Enter Total of lines 34 thru 40)	250,071,198	232,351,720
42	TOTAL Production Plant (Enter Total of lines 15, 23, 32, and 41)	768,805,935	728,294,643

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _X_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 19, 2020	Year of Report Dec. 31, 2019

ELECTRIC PLANT IN SERVICE (Continued) STATE OF IDAHO (ALLOCATED)

Line No.	Account (a)	Beginning Balance (b)	Balance End of Year (g)
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	16,825,194	16,587,091
45	(352) Structures and Improvements	17,006,996	16,708,847
46	(353) Station Equipment	135,180,533	131,138,148
47	(354) Towers and Fixtures	80,561,836	77,206,535
48	(355) Poles and Fixtures	59,162,080	59,732,112
49	(356) Overhead Conductors and Devices	77,326,242	75,734,497
50	(357) Underground Conduit	218,243	227,509
51	(358) Underground Conductors and Devices	498,188	486,986
52	(359) Roads and Trails	740,101	705,623
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	387,519,413	378,527,348
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	1,835,903	1,835,903
56	(361) Structures and Improvements	2,932,719	3,366,731
57	(362) Station Equipment	35,064,026	37,524,250
58	(363) Storage Battery Equipment	-	-
59	(364) Poles, Towers, and Fixtures	91,208,496	94,598,436
60	(365) Overhead Conductors and Devices	39,041,944	40,464,083
61	(366) Underground Conduit	10,343,293	10,668,846
62	(367) Underground Conductors and Devices	28,695,233	29,478,412
63	(368) Line Transformers	83,528,553	85,091,706
64	(369) Services	42,557,533	44,726,689
65	(370) Meters	16,113,352	16,827,950
66	(371) Installations on Customer Premises	169,414	170,194
67	(372) Leased Property on Customer Premises	-	-
68	(373) Street Lighting and Signal Systems	738,795	770,243
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	352,229,261	365,523,443
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	686,498	671,121
72	(390) Structures and Improvements	18,055,722	18,114,649
73	(391) Office Furniture and Equipment	4,845,991	3,912,030
74	(392) Transportation Equipment	8,466,379	8,277,652
75	(393) Stores Equipment	879,193	873,089
76	(394) Tools, Shop and Garage Equipment	3,826,980	3,706,858
77	(395) Laboratory Equipment	2,108,344	2,054,313
78	(396) Power Operated Equipment	13,709,362	14,021,353
79	(397) Communication Equipment	27,861,773	27,920,207
80	(398) Miscellaneous Equipment	396,414	373,337
81	SUBTOTAL (Enter Total of lines 71 thru 80)	80,836,656	79,924,609
82	(399) Other Tangible Property	121,027	120,971
83	TOTAL General Plant (Enter Total of lines 81 thru 82)	80,957,683	80,045,580
84	TOTAL (Accounts 101)	1,645,966,883	1,609,735,369
85	(102) Electric Plant Purchased	-	-
86	Less (102) Electric Plant Sold	-	-
87	(103) Experimental Electric Plant Unclassified	-	-
88	(106) Plant Unclassified	14,289,130	13,990,267
89	TOTAL Electric Plant in Service	1,660,256,013	1,623,725,636

STATE OF IDAHO --ALLOCATED

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) X An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 19, 2020	Year of Report Dec. 31, 2019

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense clearing, if applicable.

Line No.	ACCOUNT (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)	[redacted]	9,476,648	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	[redacted]		
3	Residuals and Extracted Products (Account 153)	[redacted]		
4	Plant Materials and Operating Supplies (Account 154)	[redacted]		
5	Assigned to - Construction (Estimated)	[redacted]	8,539,031	Electric
6	Assigned to - Operations and Maintenance	[redacted]		
7	Production Plant (Estimated)	[redacted]	4,207,102	Electric
8	Transmission Plant (Estimated)	[redacted]	40,177	Electric
9	Distribution Plant (Estimated)	[redacted]	607,427	Electric
10	Assigned to - Other	[redacted]	(76,643)	Electric
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	[redacted]	13,317,094	
12	Merchandise (Account 155)	[redacted]		
13	Other Materials and Supplies (Account 156)	[redacted]		
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)	[redacted]		
15	Stores Expense Undistributed (Account 163)	[redacted]		
16		[redacted]		
17		[redacted]		
18		[redacted]		
19		[redacted]		
20	TOTAL Materials and Supplies (Per Balance Sheet)	[redacted]	22,793,742	

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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 2019/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 2019/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)* 04/10/2020
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.

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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	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 2019/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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CONTROL OVER RESPONDENT

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

Berkshire Hathaway Inc.(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.

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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FOOTNOTE DATA

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, 2019, 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 2019/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Executive Officers as of December 31, 2019:		
2			
3	Chairman of the Board of Directors		
4	and Chief Executive Officer, PacifiCorp	William J. Fehrman	
5			
6	President and Chief Executive Officer,		
7	Pacific Power	Stefan A. Bird	365,000
8			
9	President and Chief Executive Officer,		
10	Rocky Mountain Power	Gary W. Hoogeveen	350,000
11			
12	Vice President, Chief Financial Officer and Treasurer,		
13	PacifiCorp	Nikki L. Kobliha	239,571
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Schedule Page: 104 Line No.: 1 Column: a

PacifiCorp sets forth compensation information for its "named executive officers" for the year ended December 31, 2019, 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.: 4 Column: c

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, 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 2019/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, 2019:	
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
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19	Cindy A. Crane	1407 West North Temple, Suite 310, Salt Lake City, UT 84116
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Schedule Page: 105 Line No.: 19 Column: a

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. 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 2019/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 2019/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	20190322-5114	03/22/2019	ER19-1419		
2	20190515-5253	05/15/2019	ER11-3643		
3					
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Schedule Page: 1061 Line No.: 1 Column: d

PacifiCorp submits tariff filing per 35.13(a)(2)(iii): OATT Revised Attachment H-1 (Revised Depreciation Rates 2019) to be effective 6/1/2019 under FERC Docket No. ER19-1419

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

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

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

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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)	46
2	204-207	Electric Plant in Service	(g)	46
3	204-207	Electric Plant in Service	(b)	75
4	204-207	Electric Plant in Service	(g)	75
5	204-207	Electric Plant in Service	(b)	99
6	204-207	Electric Plant in Service	(g)	99
7	204-207	Electric Plant in Service	(b)	104
8	204-207	Electric Plant in Service	(g)	104
9	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	20
10	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	22
11	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	24
12	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	26
13	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	28
14	219	Accum. Prov. for Depr. of Electric Utility Plant	(c)	29
15	320-323	Electric Operation and Maintenance Expenses	(b)	185
16	320-323	Electric Operation and Maintenance Expenses	(b)	197
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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)			
Clifton	06/01/2019	06/01/2029	—
Dayton	05/01/2019	05/01/2029	—
Weston	05/01/2019	05/01/2029	—
Oregon(3)			
Bend	09/30/2019	09/30/2029	7.0%
Gearhart	08/23/2019	08/23/2039	3.5%
Philomath	09/20/2019	09/20/2024	7.0%
Utah(4)			
Aurora	03/01/2019	03/01/2024	—
Beaver City	11/01/2019	11/01/2039	—
Elsinore	02/01/2019	02/01/2029	—
Emigration Canyon	07/23/2019	07/23/2039	—
Kingston	03/01/2019	03/01/2039	—
Morgan	05/01/2019	05/01/2029	—
Summit County	11/14/2019	11/14/2029	—
Tooele County	08/15/2019	08/15/2044	—
Trenton	12/15/2019	12/15/2039	—
Uintah County	04/08/2019	04/08/2029	—
West Bountiful	02/19/2019	02/19/2029	—
Washington(5)			
Granger	07/12/2019	07/12/2039	—
Harrah	09/23/2019	09/23/2039	—
Pasco	05/24/2019	05/24/2029	—
Yakima	09/25/2019	09/25/2039	—
Wyoming(6)			
None			

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

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

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

(4) In Utah, PacifiCorp collects associated taxes from customers and remits them directly to the applicable municipalities. If applicable, franchise agreement fees are an expense to PacifiCorp and are embedded in rates.

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

(6) In Wyoming, the first 1.0% of the franchise agreement fee is an expense to PacifiCorp and is embedded in rates. Any amount above the 1.0% is collected from customers and remitted directly to the applicable municipalities.

ITEM 2.

None.

ITEM 3.

None.

ITEM 4.

None.

ITEM 5.

In October 2019, PacifiCorp filed its 2019 Integrated Resource Plan ("IRP") with state commissions. The IRP includes new transmission investments that will facilitate growth in new renewable energy resources, new storage resources and expansion in new energy efficiency measures and demand-response programs. Delivery of new transmission infrastructure that will facilitate approximately 4,400 MWs of new renewable energy resources, incremental to new renewable capacity that will come online by the end of 2020, and the addition of approximately 600 MWs of new storage capacity is planned through 2023. The transmission investments included in the Energy Vision 2020, as part of the Energy Gateway Transmission expansion program, includes plans to construct the 140-mile, 500kV transmission line between Aeolus Substation near Medicine Bow in Wyoming and Jim Bridger generating facility that is expected to be placed in-service in 2020.

During the year, PacifiCorp placed into service the 29-mile high-voltage McNary-Wallula transmission line. 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, 2019.

ITEM 6.

Short-term Debt

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2019, PacifiCorp had $130 million of short-term debt outstanding at a weighted average interest rate of 2.05%.

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 ("FERC") – Docket No. ES18-3-000, dated December 20, 2017, letter order effective January 1, 2018 through December 31, 2019 and Docket No. ES20-1-000, dated December 12, 2019, letter order effective January 1, 2020 through December 31, 2021.

- 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 7 of Notes to Financial Statements in this Form No. 1.

Long-term Debt

In April 2020, PacifiCorp issued $400 million of its 2.70% First Mortgage Bonds due September 2030 and $600 million of its 3.30% First Mortgage Bonds due March 2051. PacifiCorp intends to use the net proceeds to fund capital expenditures, primarily for renewable resources and associated transmission projects and for general corporate purposes.

In March 2019, PacifiCorp issued $400 million of its 3.50% First Mortgage Bonds due June 2029 and $600 million of its 4.15% First Mortgage Bonds due February 2050. PacifiCorp used a portion of the net proceeds to repay the short-term debt that was partially incurred in January 2019 to repay all of PacifiCorp's $350 million, 5.50% First Mortgage Bonds due January 2019. PacifiCorp used the remaining net proceeds to fund capital expenditures and for general corporate purposes.

As of December 31, 2019, PacifiCorp had authorization from the OPUC and the 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. Also, as of December 31, 2019, PacifiCorp had an effective shelf registration statement with the United States Securities and Exchange Commission to issue up to $1.0 billion additional first mortgage bonds through October 2021.

State commission authorizations for the above issuance 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.

PacifiCorp must make a notice filing with the WUTC prior to any future issuance.

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, 2019, PacifiCorp estimated it would be able to issue up to $10.8 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.

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

For further discussion, refer to Note 8 of Notes to Financial Statements in this Form No. 1.

ITEM 7.

None.

ITEM 8.

For the year ended December 31, 2019, 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)	2.33%	01/26/2019	$ 71,496
IBEW 57 Laramie (WY)	1.29%	06/26/2019	9,461
IBEW 57 Power Delivery (UT, ID & WY)	2.29%	01/26/2019	1,878,830
IBEW 57 Power Supply (UT, ID & WY)	2.33%	01/26/2019	860,494
IBEW 125 (OR, WA)	2.63%	09/11/2019	24,851
IBEW 659 (OR, CA)	1.71%	04/26/2019	522,295
IBEW 659 (OR, CA)	2.84%	08/11/2019	609,544
IBEW 77 (WA)	2.09%	01/26/2019	22,593
UWUA 127 (WY)	0.60%	09/26/2019	283,860
UWUA 197 (OR)	1.51%	05/26/2019	23,035
UWUA 197 (OR)	1.55%	09/11/2019	441,568
Total			$ 4,748,027

(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 14 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, 2019, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, distributed $5.1 million of dividends, consisting of $2.4 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, 2019, other than preferred and common stock dividends declared and paid.

ITEM 11.

(Reserved.)

ITEM 12.

In July 2019, PacifiCorp completed a transaction with Eugene Water & Electric Board to acquire the remaining undivided interest in the Foote Creek I joint-owned wind generating facility and terminate a power purchase agreement with a third-party. In August 2019, PacifiCorp filed a notice of the transaction with the Wyoming Public Service Commission who approved PacifiCorp's application for a certificate of public convenience and necessity in April 2019 (Docket No. 20000-553-EN-19, Record No. 15202) requesting to repower the existing Foote Creek I wind facility.

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.

ITEM 14.

Not applicable.

Deloitte.

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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, 2019, 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 122b 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, 2019, 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 10, 2020

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	28,843,430,112	28,425,063,446
3	Construction Work in Progress (107)	200-201	2,002,448,524	1,194,168,876
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		30,845,878,636	29,619,232,322
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	10,870,776,722	11,032,877,405
6	Net Utility Plant (Enter Total of line 4 less 5)		19,975,101,914	18,586,354,917
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)		19,975,101,914	18,586,354,917
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		13,320,639	13,578,986
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,196,879	3,149,894
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	201,902,001	183,401,017
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)		102,845,814	95,479,061
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		36,427,872	14,919,564
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,278,492	2,565,604
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		353,647,867	306,864,266
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,421,766	20,006,166
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		11,969,487	49,330,121
39	Notes Receivable (141)		2,405,884	5,068,150
40	Customer Accounts Receivable (142)		420,564,473	426,619,902
41	Other Accounts Receivable (143)		30,462,387	48,930,705
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,644,908	7,691,154
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		795,724	628,710
45	Fuel Stock (151)	227	150,404,985	179,588,705
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	244,022,924	237,694,431
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)		62,585,511	48,020,660
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		924,623	1,128,478
61	Accrued Utility Revenues (173)		244,728,000	229,061,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		13,451,134	27,458,631
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,278,492	2,565,604
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)		1,182,813,498	1,263,278,901
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,683,227	29,412,802
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	1,119,161,023	1,107,326,144
73	Prelim. Survey and Investigation Charges (Electric) (183)		576,164	477,354
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)		-14,358	26,188
78	Miscellaneous Deferred Debits (186)	233	114,194,930	83,176,009
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)		3,971,176	4,554,871
82	Accumulated Deferred Income Taxes (190)	234	783,561,636	824,459,612
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,055,133,798	2,049,432,980
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		23,566,697,077	22,205,931,064

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

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

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) [x] An Original (2) [ ] A Resubmission	/ /	end of 2019/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	3,846,833,944	3,271,969,500
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	125,565,229	104,399,245
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)	-15,916,633	-12,635,042
16	Total Proprietary Capital (lines 2 through 15)		8,437,788,931	7,845,040,094
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,705,275,000	7,055,275,000
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)		24,996	36,022
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		13,445,289	10,793,807
24	Total Long-Term Debt (lines 18 through 23)		7,691,854,707	7,044,517,215
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		27,046,124	18,996,630
27	Accumulated Provision for Property Insurance (228.1)		10,159,611	8,591,841
28	Accumulated Provision for Injuries and Damages (228.2)		21,850,505	23,791,641
29	Accumulated Provision for Pensions and Benefits (228.3)		159,048,125	190,648,668
30	Accumulated Miscellaneous Operating Provisions (228.4)		34,314,273	34,600,459
31	Accumulated Provision for Rate Refunds (229)		1,500,000	2,551,062
32	Long-Term Portion of Derivative Instrument Liabilities		22,833,300	24,683,756
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		256,476,842	227,371,811
35	Total Other Noncurrent Liabilities (lines 26 through 34)		533,228,780	531,235,868
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		130,000,000	30,000,000
38	Accounts Payable (232)		624,405,083	523,289,313
39	Notes Payable to Associated Companies (233)		60,042,489	31,009,817
40	Accounts Payable to Associated Companies (234)		136,335,569	136,903,471
41	Customer Deposits (235)		44,331,534	49,781,902
42	Taxes Accrued (236)	262-263	71,717,476	48,581,847
43	Interest Accrued (237)		117,354,090	114,623,111
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)		21,382,035	20,623,597
48	Miscellaneous Current and Accrued Liabilities (242)		82,553,117	74,069,122
49	Obligations Under Capital Leases-Current (243)		3,979,527	1,788,634
50	Derivative Instrument Liabilities (244)		29,690,179	65,799,907
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		22,833,300	24,683,756
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)		1,298,998,274	1,071,827,440
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		100,135,630	76,528,076
57	Accumulated Deferred Investment Tax Credits (255)	266-267	11,203,507	13,313,777
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	201,430,606	202,519,682
60	Other Regulatory Liabilities (254)	278	1,930,223,376	2,044,239,906
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	174,829,838	180,339,430
63	Accum. Deferred Income Taxes-Other Property (282)		2,889,829,879	2,910,580,066
64	Accum. Deferred Income Taxes-Other (283)		297,173,549	285,789,510
65	Total Deferred Credits (lines 56 through 64)		5,604,826,385	5,713,310,447
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		23,566,697,077	22,205,931,064

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, 2019, the interest rate on the outstanding loan balance was 2.05%.

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, 2018, the interest rate on the outstanding loan balance was 2.85%.

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

As of December 31, 2019, Account 236, Taxes accrued, included $28,316,216 of income taxes payable to Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

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

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.

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	5,065,712,793	5,090,358,956		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,427,820,299	2,470,313,861		
5	Maintenance Expenses (402)	320-323	404,986,660	413,932,883		
6	Depreciation Expense (403)	336-337	879,989,526	908,461,901		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	49,689,883	46,883,718		
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)		148,092	150,275		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	199,137,026	201,255,354		
15	Income Taxes - Federal (409.1)	262-263	151,665,847	162,384,813		
16	- Other (409.1)	262-263	34,920,585	41,626,061		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,188,782,866	450,529,508		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,311,969,270	648,977,032		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,738,724	-3,152,015		
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)		173	181		
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)		4,027,515,812	4,048,492,341		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,038,196,981	1,041,866,615		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
5,065,712,793	5,090,358,956					2
						3
2,427,820,299	2,470,313,861					4
404,986,660	413,932,883					5
879,989,526	908,461,901					6
						7
49,689,883	46,883,718					8
5,083,195	5,083,195					9
						10
						11
148,092	150,275					12
						13
199,137,026	201,255,354					14
151,665,847	162,384,813					15
34,920,585	41,626,061					16
1,188,782,866	450,529,508					17
1,311,969,270	648,977,032					18
-2,738,724	-3,152,015					19
						20
						21
173	181					22
						23
						24
4,027,515,812	4,048,492,341					25
1,038,196,981	1,041,866,615					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,038,196,981	1,041,866,615		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		2,141,746	1,500,711		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,120,904	1,372,254		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		263,038	79,216		
35	Nonoperating Rental Income (418)		196,104	275,014		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	23,563,311	20,869,978		
37	Interest and Dividend Income (419)		18,097,499	14,250,874		
38	Allowance for Other Funds Used During Construction (419.1)		72,317,120	34,835,895		
39	Miscellaneous Nonoperating Income (421)		6,570,592	-728,378		
40	Gain on Disposition of Property (421.1)		3,595,254	939,906		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		124,097,684	70,492,530		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		200,037	88,035		
44	Miscellaneous Amortization (425)		1,330,948	1,329,336		
45	Donations (426.1)		2,342,288	2,387,899		
46	Life Insurance (426.2)		-8,140,640	-3,252,632		
47	Penalties (426.3)		-1,272,934	1,112,093		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,092,950	1,239,589		
49	Other Deductions (426.5)		34,550,630	7,940,472		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		30,103,279	10,844,792		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	350,102	340,043		
53	Income Taxes-Federal (409.2)	262-263	-2,461,788	1,079,374		
54	Income Taxes-Other (409.2)	262-263	-557,526	243,788		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	63,463,964	109,004,879		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	62,277,453	109,467,521		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		352,431	236,733		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,835,132	963,830		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		95,829,537	58,683,908		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		369,853,259	358,695,455		
63	Amort. of Debt Disc. and Expense (428)		3,892,240	4,027,405		
64	Amortization of Loss on Reaquired Debt (428.1)		583,695	584,922		
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)		177,870	69,069		
68	Other Interest Expense (431)		24,622,419	17,922,378		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		36,284,269	18,446,680		
70	Net Interest Charges (Total of lines 62 thru 69)		362,834,188	362,841,523		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		771,192,330	737,709,000		
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)		771,192,330	737,709,000		

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, 2019 and 2018, depreciation expense associated with transportation equipment was $16,386,376 and $15,829,896, 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, 2019 and 2018, payroll taxes were $40,623,353 and $39,770,569, 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 2019/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		3,227,391,376	2,948,638,352
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)		747,629,019	716,839,022
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-4,236,163	(8,732,124)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-4,236,163	(8,732,124)
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	-175,000,000	(450,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-175,000,000	(450,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	2,397,327	20,808,028
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,798,019,657	3,227,391,376
	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 2019/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)		48,814,287	44,578,124
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		48,814,287	44,578,124
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,846,833,944	3,271,969,500
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		104,399,245	104,337,295
50	Equity in Earnings for Year (Credit) (Account 418.1)		23,563,311	20,869,978
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unappropriated Retained Earnings (Account 216)		-2,397,327	(20,808,028)
53	Balance-End of Year (Total lines 49 thru 52)		125,565,229	104,399,245

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

Outstanding shares of preferred stock as of December 31, 2019 and declared dividends on preferred stock during the year ended December 31, 2019 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, 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.: 37 Column: c

During the year ended December 31, 2019, paid distributions from subsidiaries of PacifiCorp were as follows:

Fossil Rock Fuels, LLC	2,397,000
Trapper Mining Inc.	327
	$ 2,397,327

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

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.: 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 2019/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)	771,192,330	737,709,000
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	897,855,483	926,028,121
5	Amortization:	56,127,827	53,322,235
6			
7			
8	Deferred Income Taxes (Net)	-121,999,893	-198,910,166
9	Investment Tax Credit Adjustment (Net)	-3,091,155	-3,388,748
10	Net (Increase) Decrease in Receivables	-1,814,992	22,276,393
11	Net (Increase) Decrease in Inventory	22,855,227	15,493,125
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-9,920,410	88,063,038
14	Net (Increase) Decrease in Other Regulatory Assets	-64,974,675	-19,930,064
15	Net Increase (Decrease) in Other Regulatory Liabilities	9,960,664	107,413,446
16	(Less) Allowance for Other Funds Used During Construction	72,317,120	34,835,895
17	(Less) Undistributed Earnings from Subsidiary Companies	21,165,984	61,950
18	Amounts Due To/From Affiliates (Net)	22,900,991	69,557,216
19	Derivative Collateral (Net)	12,400,000	14,900,000
20	Other Operating Activities:	19,842,961	4,701,781
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,517,851,254	1,782,337,532
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-2,247,610,148	-1,291,567,102
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	-72,317,120	-34,835,895
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-2,175,293,028	-1,256,731,207
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	7,608,830	4,229,118
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies	2,665,000	2,668,000
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 2019/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:	733,463	-2,495,368
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-2,164,285,735	-1,252,329,457
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	989,337,013	593,102,815
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	99,950,000	
67	Other (provide details in footnote):	29,000,000	22,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,118,287,013	615,102,815
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-350,000,000	-586,200,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-802,544	-1,118,205
77	Repayment of Finance Lease Principal in Capital Lease Obligations	-1,479,581	-1,736,324
78	Net Decrease in Short-Term Debt (c)		-50,000,347
79			
80	Dividends on Preferred Stock	-161,902	-161,902
81	Dividends on Common Stock	-175,000,000	-450,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	590,842,986	-474,113,963
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-55,591,495	55,894,112
87			
88	Cash and Cash Equivalents at Beginning of Period	84,255,851	28,361,739
89			
90	Cash and Cash Equivalents at End of period	28,664,356	84,255,851

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

Includes depreciation expense associated with transportation equipment and finance lease assets of $17,865,957 and $17,566,220, during the years ended December 31, 2019 and 2018, respectively.

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

	Years Ended December 31, 2019	Years Ended December 31, 2018
Amortization of software development & other intangibles	$ 51,020,831	$ 48,213,054
Amortization of electric plant acquisition adjustments	5,083,195	5,083,195
Amortization of a regulatory asset	23,801	25,986
	$ 56,127,827	$ 53,322,235

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

	Years Ended December 31, 2019	Years Ended December 31, 2018
Depreciation and depletion included in cost of fuel	$ 2,078,082	$ 2,076,162
Net gain on sale of property	(4,186,776)	(955,310)
Write-off of assets under construction	6,610,739	1,903,891
Costs associated with the early retirement of Cholla Unit No. 4 generating facility	23,431,738	
Change in corporate owned life insurance cash surrender value	(8,109,131)	(3,241,715)
Amortization of debt issuance expenses and bond discount/premium	3,881,214	4,016,379
Changes in derivative contract assets/liabilities, net	(822,620)	(941,213)
Other	(3,040,285)	1,843,587
	$ 19,842,961	$ 4,701,781

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, 2019	Years Ended December 31, 2018
Other investments/special funds	$ 915,947	$ 1,986,133
Investment in long-term incentive plan securities	(182,484)	(4,481,501)
	$ 733,463	$ (2,495,368)

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

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.

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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 provision for 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 guidance. 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 guidance, 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 recognized in net income, returned to customers 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 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):

	2019	2018
Cash (131)	$ 10	$ 20
Other special funds (128)	7	15
Temporary cash investments (136)	12	49
Total cash and cash equivalents and restricted cash and cash equivalents	$ 29	$ 84

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, 2019 and 2018, 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. As of December 31, 2019 and 2018, the allowance for doubtful accounts totaled $8 million, which is included in accumulated provision for uncollectible accounts on the Comparative Balance Sheet.

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 revenue 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.

Leases

PacifiCorp has non-cancelable operating leases primarily for land, office space, office equipment, and generating facilities and finance leases consisting primarily of office buildings, natural gas pipeline facilities, and generating facilities. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp does not include options in its lease calculations unless there is a triggering event indicating PacifiCorp is reasonably certain to exercise the option. PacifiCorp's accounting policy is to not recognize lease obligations and corresponding right-of-use assets for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets will be evaluated for impairment in accordance with GAAP when a triggering event has occurred that might affect the value and use of the assets being leased.

PacifiCorp's leases of generating facilities generally are in the form of long-term purchases of electricity, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

PacifiCorp follows FERC accounting and reporting requirements and records operating and finance right-of-use assets in Account 101.1, Property under capital leases, and the current and noncurrent operating and finance lease liabilities are recorded in Account 243, Obligations under capital leases – Current and Account 227, Obligations under capital leases – Noncurrent, respectively.

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 commissions. 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 commissions.

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

On November 21, 2019, the FERC issued Order 864, "Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes" requiring public utility transmission providers with transmission rates under an Open Access Transmission Tariff to account for changes caused by the Tax Cuts and Jobs Act, enacted on December 22, 2017 and effective January 1, 2018 ("2017 Tax Reform"). The FERC is requiring public utilities with transmission formula rates to include a mechanism in those transmission formula rates to deduct any excess accumulated deferred income taxes ("ADIT") from or add any deficient ADIT to their rate bases. Public utilities with transmission formula rates are also required to incorporate a mechanism to decrease or increase their income tax allowances by any amortized excess or deficient ADIT, respectively. Finally, the FERC is requiring public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track information related to excess or deficient ADIT. The FERC is requiring each public utility with transmission formula rates to submit a filing to demonstrate compliance with the final rule, including revisions to its transmission formula rates, as necessary, within the later of (1) 30 days of the effective date of this ruling or (2) the public utility's next annual informational filing following the issuance of this order. PacifiCorp is implementing the adoption of this guidance in its transmission rates under the Open Access Transmission Tariff in FERC Docket No. ER11-3643, to be filed by May 15, 2020.

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, which creates FASB Accounting Standards Codification ("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. Following the issuance of ASU No. 2016-02, the FASB issued several ASUs that clarified the implementation guidance for ASU No. 2016-02 but did not change the core principle of the guidance. PacifiCorp has elected to utilize various practical expedients available to adopt ASU No. 2016-02, including (1) the package of three not requiring a reassessment of (i) whether any expired or existing contracts are or contain leases; (ii) the lease classification for any expired or existing leases; and (iii) initial direct costs for any existing leases; (2) using hindsight in determining the lease term; and (3) not requiring a reassessment of whether existing or expired land easements that were not previously accounted for as leases under ASC Topic 840 are or contain a lease under ASC Topic 842. PacifiCorp adopted this guidance for all applicable contracts in effect as of January 1, 2019 under a modified retrospective method and the adoption did not have a cumulative effect impact at the date of initial adoption. For FERC reporting, PacifiCorp follows the accounting guidance for leases in accordance with FERC Order No. AI19-1-000, "Accounting and Financial Reporting for Leases".

Subsequent Events

PacifiCorp has evaluated the impact of events occurring after December 31, 2019 up to February 21, 2020, 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 10, 2020. 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 3.3% and 3.5% for the years ended December 31, 2019 and 2018, respectively, including the impacts of accelerated depreciation for Oregon's share of certain wind equipment retired as a result of wind repowering projects placed into service in 2019 and accelerated depreciation for Utah's share of certain thermal plant units in 2018.

PacifiCorp filed a depreciation study in 2018 with all of its state public utility commissions, except the California Public Utilities Commission. PacifiCorp is currently working with the commissions and interested parties and anticipates revised depreciation rates to be effective January 1, 2021.

(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 included in net utility plant, as of December 31, 2019 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67 %	$ 1,481	$ 693	$ 9
Hunter No. 1	94	484	188	1
Hunter No. 2	60	305	118	2
Wyodak	80	473	238	1
Colstrip Nos. 3 and 4	10	254	141	2
Hermiston	50	181	92	5
Craig Nos. 1 and 2	19	368	127	—
Hayden No. 1	25	75	40	—
Hayden No. 2	13	43	24	—
Transmission and distribution facilities	Various	808	306	103
Total		$ 4,472	$ 1,967	$ 123

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Comparative Balance Sheet (in millions):

	As of December 31, 2019
Right-of-use assets:	
Operating leases	$ 12
Finance leases	19
Total right-of-use assets	$ 31
Lease liabilities:	
Operating leases	$ 12
Finance leases	19
Total lease liabilities	$ 31

The following table summarizes PacifiCorp's lease costs (in millions):

	Year Ended December 31, 2019
Variable	$ 77
Operating	3
Finance:	
Amortization	1
Interest	2
Short-term	2
Total lease costs	$ 85
Weighted-average remaining lease term (years):	
Operating leases	14.0
Finance leases	9.1
Weighted-average discount rate:	
Operating leases	3.7%
Finance leases	10.6%

Cash payments associated with operating and finance lease liabilities approximated lease cost for the year ended December 31, 2019.

PacifiCorp has the following remaining lease commitments (in millions):

	December 31, 2019		
	Operating	**Finance**	**Total**
2020	$ 2	$ 3	$ 5
2021	2	7	9
2022	2	3	5
2023	2	2	4
2024	1	2	3
Thereafter	7	14	21
Total undiscounted lease payments	16	31	47
Less - amounts representing interest	(4)	(12)	(16)
Lease liabilities	$ 12	$ 19	$ 31

(6) Regulatory Matters

Regulatory Assets

PacifiCorp had regulatory assets not earning a return on investment of $605 million and $631 million as of December 31, 2019 and 2018, respectively.

(7) Short-term Debt and Credit Facilities

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

2019:		
Credit facilities	$	1,200
Less:		
Short-term debt		(130)
Tax-exempt bond support		(256)
Net credit facilities	$	814
2018:		
Credit facilities	$	1,200
Less:		
Short-term debt		(30)
Tax-exempt bond support		(89)
Net credit facilities	$	1,081

As of December 31, 2019, PacifiCorp was in compliance with the covenants of its credit facilities and letter of credit arrangements.

PacifiCorp has a $600 million unsecured credit facility expiring in June 2022 and a $600 million unsecured credit facility expiring in June 2022 with one remaining one-year extension option 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, 2019 and 2018, the weighted average interest rate on commercial paper borrowings outstanding was 2.05% and 2.85%, 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, 2019 and 2018, PacifiCorp had $13 million and $184 million, respectively, of fully available letters of credit issued under committed arrangements. As of December 31, 2019 and 2018, $13 million and $14 million, respectively, support certain transactions required by third parties and generally 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.

(8) Long-term Debt

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

In April 2020, PacifiCorp issued $400 million of its 2.70% First Mortgage Bonds due September 2030 and $600 million of its 3.30% First Mortgage Bonds due March 2051. PacifiCorp intends to use the net proceeds to fund capital expenditures, primarily for renewable resources and associated transmission projects and for general corporate purposes.

In March 2019, PacifiCorp issued $400 million of its 3.50% First Mortgage Bonds due June 2029 and $600 million of its 4.15% First Mortgage Bonds due February 2050. PacifiCorp used a portion of the net proceeds to repay the short-term debt that was partially incurred in January 2019 to repay all of PacifiCorp's $350 million, 5.50% First Mortgage Bonds due January 2019. PacifiCorp used the remaining net proceeds to fund capital expenditures and for general corporate purposes.

As of December 31, 2019, PacifiCorp had authorization 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 Washington Utilities and Transportation Commission ("WUTC") prior to any future issuance. Also, as of December 31, 2019, PacifiCorp had 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.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $29 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2019.

As of December 31, 2019, the annual principal maturities of long-term debt for 2020 and thereafter, are as follows (in millions):

	Long-term Debt
2020	$ 38
2021	420
2022	605
2023	449
2024	591
Thereafter	5,602
Total	7,705
Unamortized discount	(13)
Total	$ 7,692

(9) Income Taxes

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

	2019	2018
Current:		
Federal	$ 149	$ 163
State	34	42
Total	183	205
Deferred:		
Federal	(127)	(190)
State	5	(9)
Total	(122)	(199)
Investment tax credits	(3)	(3)
Total income tax expense	$ 58	$ 3

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:

	2019	2018
Federal statutory income tax rate	21%	21%
State income taxes, net of federal income tax benefit	3	4
Amortization of excess deferred income taxes	(11)	(17)
Effects of ratemaking	(2)	—
Federal income tax credits	(3)	(7)
Other	(1)	(1)
Effective income tax rate	7%	—%

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 $91 million of Oregon allocated excess deferred income taxes pursuant to the Oregon Renewable Adjustment Clause ("RAC") settlement, whereby a portion of Oregon allocated excess deferred income taxes was used to accelerate depreciation on Oregon's share of certain repowered wind facilities. Amortization of excess deferred income taxes in 2018 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, 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):

	2019	2018
Deferred income tax assets:		
Regulatory liabilities	$ 476	$ 503
Employee benefits	83	91
Derivative contracts and unamortized contract values	33	45
State carryforwards	70	77
Asset retirement obligations	61	53
Other	61	55
	784	824
Deferred income tax liabilities:		
Property, plant and equipment	(3,065)	(3,091)
Regulatory assets	(276)	(273)
Other	(21)	(12)
	(3,362)	(3,376)
Net deferred income tax liability	$ (2,578)	$ (2,552)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2019 (in millions):

	State
Net operating loss carryforwards	$ 1,140
Deferred income taxes on net operating loss carryforwards	$ 51
Expiration dates	2023 - 2032
Tax credit carryforwards	$ 19
Expiration dates	2020 - 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, 2011, with the exception of California, Utah and Oregon, for which the statutes have expired through December 31, 2009. In addition, Idaho's statute of limitations has expired through December 31, 2015, 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.

2017 Tax Reform

2017 Tax Reform enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the United States federal corporate income tax rate from 35% to 21%. In 2018, PacifiCorp agreed to refund or defer the impact of the tax law change with each of its state regulatory commissions. Although PacifiCorp anticipated amortizing protected excess deferred income taxes using the Average Rate Assumption Method as originally disclosed in its 2018 FERC Form No. 1, PacifiCorp will be using the Reverse South Georgia Method to amortize protected excess deferred income taxes over the remaining regulatory life of each asset or group of assets in all jurisdictions. The period of time over which non-protected excess deferred income taxes are amortized will be determined in future proceedings, as previously disclosed, or as noted in the applicable state sections below.

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 no later than PacifiCorp's next general rate proceeding. The settlement, which resulted in a rate reduction of $48 million, or 3.7%, effective February 1, 2019, was approved by the OPUC in January 2019.

In December 2018, PacifiCorp filed a 2019 RAC application requesting recovery of $37 million, or a 2.8% increase in rates, associated with repowering of approximately 900 megawatts of company-owned and installed wind facilities expected to be completed in 2019. In March 2019, the application was updated to request recovery of $32 million, or a 2.5% increase in rates. In August 2019, PacifiCorp filed an all-party settlement for the 2019 RAC that was approved by the OPUC in September 2019, providing for a total rate increase of $24 million, or 1.8%, subject to final cost updates. The settlement agreement provides for rates to be increased as the repowering projects are completed. Based on the in-service dates and final cost updates, the first rate increase of $9 million or 0.7% was effective October 1, 2019, for four repowered facilities, the second rate increase of $1 million, or 0.1%, was effective December 1, 2019, for one repowered facility and the third rate increase of $5 million or 0.4%, was effective January 1, 2020, for two repowered facilities. A final rate increase of $4.8 million, or 0.4 percent, was effective April 1, 2020 for the final two remaining repowered facilities that were placed in service by the end of February 2020.

As part of the commission-approved RAC settlement, parties agreed that the Oregon-allocated net book value of certain undepreciated equipment replaced as a result of those repowerings captured in the 2019 RAC will be depreciated and offset with excess deferred income taxes resulting from 2017 Tax Reform. In 2019, accelerated depreciation of $120 million and offsetting amortization of excess deferred income taxes was recognized based on repowering activities completed through December 31, 2019.

In February 2020, PacifiCorp filed a general rate case in Oregon requesting an increase in base rates of $78 million, or 6.0%, effective January 1, 2021, a separate tariff rider to recover costs associated with the early retirement of Cholla Unit 4 for an increase of $17 million annually from January 2021 through April 2025 and an annual credit to customers of $25 million for amortization of remaining deferred income tax benefits associated with 2017 Tax Reform over a three-year period beginning January 2021. The request for the increase in base rates reflects recovery of Energy Vision 2020 investments, updated depreciation rates and rate design modernization proposals.

Wyoming

In March 2020, PacifiCorp filed a general rate case in Wyoming requesting an increase in base rates of $7 million, or 1.1 percent, effective January 1, 2021. The increase reflects recovery of Energy Vision 2020 investments, updated depreciation rates and rate design modernization proposals. The request includes a revision to the Energy Cost Adjustment Mechanism ("ECAM") to eliminate the sharing band, approval to discontinue operations and cost recovery for the early retirement of Cholla Unit No. 4 generating facility. The proposed increase reflects several rate mitigation measures that include use of the remaining 2017 Tax Reform benefits to buy down plant balances and creation of regulatory assets for certain coal-fired generation units.

In April 2018, PacifiCorp filed a partial settlement related to the impact of 2017 Tax Reform with the Wyoming Public Service Commission ("WPSC") that provided 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, 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 balances. 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 and a $4 million offset to PacifiCorp's 2018 ECAM rates. The order reflected $20 million of current tax savings and was updated to reflect a projection of $7 million for amortization of excess deferred income tax balances. In April 2019, PacifiCorp filed a new application updating the amount of benefits being returned to customers. PacifiCorp continued the interim rate reduction that includes the previously approved $23 million and an additional $4 million reduction to offset the 2019 ECAM, effective June 15, 2019. A settlement agreement was filed in November 2019 in which the parties agreed to an additional rate reduction of $9 million effective December 1, 2019 through the end of calendar year 2020. The WPSC approved the settlement agreement at its hearing held in November 2019.

Washington

In December 2019, PacifiCorp submitted its 2021 general rate case with the WUTC requesting an overall decrease to rates of approximately $4 million, or 1.1%, effective January 1, 2021. The case includes an increase in revenue requirement of $3 million, offset by a proposed ten-year annual surcredit of $7 million, including interest, to customers primarily associated with the amortization of excess deferred income taxes from 2017 Tax Reform. The case includes a request for approval of a new cost allocation methodology, updated depreciation rates, recovery of Energy Vision 2020 investments, and rate design modernization proposals.

Idaho

In May 2018, the IPUC approved a rate reduction of $6 million, or 2.2%, effective June 1, 2018 through May 31, 2019, to pass back a portion of the current tax benefits associated with 2017 Tax Reform. In March 2019, an all-party settlement resolving the treatment of the remaining tax savings was filed with the IPUC. In May 2019, the IPUC approved the all-party settlement, which includes the amortization of non-protected excess deferred income taxes over 7 years, resulting in the rate reduction for current tax savings being adjusted to $8 million per year, effective June 1, 2019, and $3 million related to amortization of excess deferred income taxes from 2017 Tax Reform being applied as an offset to the 2019 ECAM.

California

In April 2018, PacifiCorp filed a general rate case with the California Public Utilities Commission ("CPUC") for an overall rate increase of $1 million, or 0.9%, effective January 1, 2019. A CPUC decision was issued in February 2020, resulting in an approximate $6 million, or 6%, rate decrease effective February 6, 2020. As part of the CPUC decision, non-protected excess deferred income taxes are being returned to California customers over three years.

(10) 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.

Defined Benefit Plans

PacifiCorp's pension plans include non-contributory defined benefit pension plans, collectively the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to all non-union employees hired after January 1, 2008. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009 earned benefits based on a cash balance formula through December 31, 2016. Effective January 1, 2017, non-union employee participants with a cash balance benefit in the Retirement Plan are no longer eligible to receive pay credits in their cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011 as they are now being provided with enhanced 401(k) Plan benefits. However, certain limited union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula. The SERP was closed to new participants as of March 21, 2006 and froze future accruals for active participants as of December 31, 2014.

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

	Pension		Other Postretirement	
	2019	2018	2019	2018
Service cost	$ —	$ —	$ 2	$ 2
Interest cost	44	43	12	11
Expected return on plan assets	(67)	(72)	(21)	(21)
Settlement	—	22	—	—
Net amortization	11	13	—	(6)
Net periodic benefit (credit) cost	$ (12)	$ 6	$ (7)	$ (14)

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	
	2019	2018	2019	2018
Plan assets at fair value, beginning of year	$ 942	$ 1,111	$ 297	$ 332
Employer contributions	4	4	1	1
Participant contributions	—	—	5	5
Actual return on plan assets	181	(52)	55	(16)
Settlement	—	(52)	—	—
Benefits paid	(91)	(69)	(24)	(25)
Plan assets at fair value, end of year	$ 1,036	$ 942	$ 334	$ 297

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

	Pension		Other Postretirement	
	2019	2018	2019	2018
Benefit obligation, beginning of year	$ 1,105	$ 1,251	$ 298	$ 331
Service cost	—	—	2	2
Interest cost	44	43	12	11
Participant contributions	—	—	5	5
Actuarial loss (gain)	109	(68)	11	(26)
Settlement	—	(52)	—	—
Benefits paid	(91)	(69)	(24)	(25)
Benefit obligation, end of year	$ 1,167	$ 1,105	$ 304	$ 298
Accumulated benefit obligation, end of year	$ 1,167	$ 1,105		

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	
	2019	2018	2019	2018
Plan assets at fair value, end of year	$ 1,036	$ 942	$ 334	$ 297
Less - Benefit obligation, end of year	1,167	1,105	304	298
Funded status	$ (131)	$ (163)	$ 30	$ (1)
Amounts recognized on the Comparative Balance Sheet:				
Other special funds (128)	$ —	$ —	$ 30	$ —
Miscellaneous current and accrued liabilities (242)	(4)	(4)	—	—
Accumulated provision for pension and benefits (228.3)	(127)	(159)	—	(1)
Amounts recognized	$ (131)	$ (163)	$ 30	$ (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 $57 million and $52 million as of December 31, 2019 and 2018, respectively. These assets are not included in the plan assets in the above table, but are reflected in temporary cash investments, totaling $- million and $1 million as of December 31, 2019 and 2018, respectively, and other investments, totaling $57 million and $51 million as of December 31, 2019 and 2018, respectively, on the Comparative Balance Sheet.

The projected benefit obligation and the accumulated benefit obligation for the pension plan were both in excess of the fair value of the plan assets as of December 31, 2019.

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	
	2019	2018	2019	2018
Net loss (gain)	$ 442	$ 461	$ (26)	$ (2)
Regulatory deferrals	1	(1)	6	7
Total	$ 443	$ 460	$ (20)	$ 5

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2019 and 2018 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
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
Net (gain) loss arising during the year	(11)	5	(6)
Net amortization	(10)	(1)	(11)
Total	(21)	4	(17)
Balance, December 31, 2019	$ 422	$ 21	$ 443

	Regulatory Asset (Liability)
Other Postretirement	
Balance, December 31, 2017	$ (11)
Net loss arising during the year	10
Net amortization	6
Total	16
Balance, December 31, 2018	5
Net loss arising during the year	(25)
Net amortization	—
Total	(25)
Balance, December 31, 2019	$ (20)

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension		Other Postretirement	
	2019	2018	2019	2018
Benefit obligations as of December 31:				
Discount rate	3.25%	4.25%	3.20%	4.25%
Rate of compensation increase	N/A	N/A	N/A	N/A
Interest crediting rates for cash balance plan(1)(2)	2.27%	3.40%	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.25%	3.60%	4.25%	3.60%
Expected return on plan assets	7.00	7.00	6.86	6.86
Rate of compensation increase	N/A	N/A	N/A	N/A

(1) 2019 Cash Balance Interest Crediting Rate assumption is 2.27% for 2020-2021 and 2.10% for 2022 and all future years for nonunion participants and 2.16% for 2020-2021 and 2.70% for 2022+ for union participants.

(2) 2018 Cash Balance Interest Crediting Rate assumption was 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.

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 2020. 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. PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. PacifiCorp evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plan.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2020 through 2024 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2020	$ 112	$ 27
2021	98	24
2022	94	23
2023	89	23
2024	83	21
2025-2029	350	94

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, 2019:

	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, 2019:				
Cash and cash equivalents	$ —	$ 24	$ —	$ 24
Debt securities:				
United States government obligations	21	—	—	21
Corporate obligations	—	94	—	94
Municipal obligations	—	10	—	10
Agency, asset and mortgage-backed obligations	—	42	—	42
Equity securities:				
United States companies	355	—	—	355
International companies	15	—	—	15
Investment funds[(2)]	55	—	—	55
Total assets in the fair value hierarchy	$ 446	$ 170	$ —	616
Investment funds[(2)] measured at net asset value				327
Limited partnership interests[(3)] measured at net asset value				93
Investments at fair value				$ 1,036
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

(1) Refer to Note 13 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 2019 and 2018, and are invested in United States and international securities of approximately 51% and 49%, respectively, for 2019 and 68% and 32%, respectively, for 2018.

(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, 2019:				
Cash and cash equivalents	$ 8	$ 1	$ —	$ 9
Debt securities:				
United States government obligations	12	—	—	12
Corporate obligations	—	26	—	26
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	22	—	22
Equity securities:				
United States companies	74	—	—	74
International companies	4	—	—	4
Investment funds[(2)]	44	—	—	44
Total assets in the fair value hierarchy	$ 142	$ 51	$ —	193
Investment funds[(2)] measured at net asset value				136
Limited partnership interests[(3)] measured at net asset value				5
Investments at fair value				$ 334
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

(1) Refer to Note 13 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 56% and 44%, respectively, for 2019 and 59% and 41%, respectively, for 2018, and are invested in United States and international securities of approximately 79% and 21%, respectively, for 2019 and 90% and 10%, respectively, for 2018.

(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 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.

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**	**2019**	**2018**	**Funding improvement plan**	**Surcharge imposed under PPA(1)**	**2019**	**2018**	**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	2017, 2016

(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, 2017 and 2016. Information for the plan year beginning July 1, 2018 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire 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, 2019, 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 $40 million and $39 million for the years ended December 31, 2019 and 2018, respectively.

(11) 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 $1,019 million and $994 million as of December 31, 2019 and 2018, respectively.

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

	2019	2018
Beginning balance	$ 227	$ 215
Change in estimated costs	27	9
Additions	9	—
Retirements	(15)	(5)
Accretion	9	8
Ending balance	$ 257	$ 227

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.

(12) 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 13 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, 2019:					
Not designated as hedging contracts[(1)]:					
Commodity assets	$ 15	$ 2	$ 4	$ —	$ 21
Commodity liabilities	(3)	—	(31)	(50)	(84)
Total	12	2	(27)	(50)	(63)
Total derivatives	12	2	(27)	(50)	(63)
Cash collateral receivable	—	—	20	27	47
Total derivatives - net basis	$ 12	$ 2	$ (7)	$ (23)	$ (16)
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 (payable) receivable	(2)	—	16	45	59
Total derivatives - net basis	$ 25	$ 3	$ (41)	$ (25)	$ (38)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2019 and 2018, a regulatory asset of $62 million and $96 million, respectively, was recorded related to the net derivative liability of $63 million and $97 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):

	2019	2018
Beginning balance	$ 96	$ 101
Changes in fair value recognized in regulatory assets	(37)	12
Net (losses) gains reclassified to operating revenue	(34)	(68)
Net gains (losses) reclassified to energy costs	37	(51)
Ending balance	$ 62	$ 96

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	2019	2018
Electricity sales	Megawatt hours	(2)	(6)
Natural gas purchases	Decatherms	129	117

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 agreements, including 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 agreements 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" if there is a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2019, 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 $80 million and $113 million as of December 31, 2019 and 2018, respectively, for which PacifiCorp had posted collateral of $47 million and $61 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, 2019 and 2018, PacifiCorp would have been required to post $27 million and $35 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.

(13) 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, 2019:					
Assets:					
Commodity derivatives	$ —	$ 21	$ —	$ (7)	$ 14
Money market mutual funds(2)	17	—	—	—	17
Investment funds	25	—	—	—	25
	$ 42	$ 21	$ —	$ (7)	$ 56
Liabilities - Commodity derivatives	$ —	$ (84)	$ —	$ 54	$ (30)
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)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $47 million and $59 million as of December 31, 2019 and 2018, respectively.

(2) Amounts are included in other investments and special funds 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 12 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):

	2019		2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,692	$ 9,280	$ 7,045	$ 7,833

(14) 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 is a party to the 2016 amended Klamath Hydroelectric Settlement Agreement ("KHSA"), which is intended to resolve disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA does not guarantee dam removal. Instead, it establishes a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal can occur consistent with the settlement's terms. For PacifiCorp, the key elements of the settlement include: (1) a contribution from PacifiCorp's Oregon and California customers capped at $200 million plus $250 million in California bond funds; (2) complete indemnification from harms associated with dam removal; (3) transfer of the FERC license to a third-party dam removal entity, the Klamath River Renewal Corporation ("KRRC"), who would conduct dam removal; and (4) ability for PacifiCorp to operate the facilities for the benefit of customers until dam removal commences.

In September 2016, the KRRC and PacifiCorp filed a joint application with the FERC to transfer the license for the four mainstem Klamath dams from PacifiCorp to the KRRC. Over the past two years, the KRRC has been supplementing the application with additional information about its financial, technical, and legal capacity to become the licensee. In July 2019, the KRRC provided the FERC with additional information about its financial capacity to become a licensee, including updated cost estimates, and its insurance, bonding and liability transfer package. The FERC is evaluating the KRRC's information and the proposed license transfer. The KRRC will continue to refine its insurance, bonding and liability transfer package, and PacifiCorp will review the KRRC's capacity to fulfill its indemnity obligation under the KHSA. If certain conditions in the amended KHSA are not satisfied (e.g., inadequate funding or inability of KRRC to satisfy its indemnification obligation) and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

The United States Court of Appeals for the District of Columbia Circuit issued a decision in the *Hoopa Valley Tribe v. FERC* litigation, in January 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. This decision has the potential to limit the ability of the States to impose water quality conditions on new and relicensed projects. Environmental interests, supported by California, Oregon and other states, asked the court to rehear the case, which was denied. Subsequently, environmental groups, supported by numerous states, filed a petition for certiorari before the United States Supreme Court, which was denied on December 9, 2019, thereby allowing the circuit court opinion to stand as a final and unappealable decision.

As of December 31, 2019, PacifiCorp's assets included $29 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 in Utah, Wyoming and Idaho through December 31, 2022.

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 $168 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, 2019 are as follows (in millions):

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 279	$ 177	$ 174	$ 168	$ 164	$ 1,810	$ 2,772
Purchased electricity contracts - non-commercially operable	7	52	52	53	53	987	1,204
Fuel contracts	832	519	316	245	248	775	2,935
Construction commitments	844	6	—	—	4	—	854
Transmission	101	86	77	71	56	429	820
Easements	10	12	12	12	11	349	406
Maintenance, service and other contracts	329	49	41	34	32	204	689
Total commitments	$ 2,402	$ 901	$ 672	$ 583	$ 568	$ 4,554	$ 9,680

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 solar or 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. Refer to Note 5 for information on lease commitments.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in operating expenses on the Statement of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2019 and 2018 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.

Easements

PacifiCorp has non-cancelable easements for land on which certain of its assets, primarily wind-powered generating facilities, are located.

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.

(15) 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.

(16) Common Shareholder's Equity

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, 2019, 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, 2019, PacifiCorp's actual common equity percentage, as calculated under this measure, was 53%, and PacifiCorp would have been permitted to dividend $2.4 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, 2019, 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 7.

(17) 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):

	2019	2018
Interest paid, net of amounts capitalized	$ 340	$ 349
Income taxes paid, net(1)	$ 160	$ 131
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 293	$ 184

(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 2019/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				(15,266,178)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				696,196
3	Preceding Quarter/Year to Date Changes in Fair Value				1,934,940
4	Total (lines 2 and 3)				2,631,136
5	Balance of Account 219 at End of Preceding Quarter/Year				(12,635,042)
6	Balance of Account 219 at Beginning of Current Year				(12,635,042)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				578,074
8	Current Quarter/Year to Date Changes in Fair Value				(3,859,665)
9	Total (lines 7 and 8)				(3,281,591)
10	Balance of Account 219 at End of Current Quarter/Year				(15,916,633)

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			(15,266,178)	[redacted]	[redacted]
2			696,196	[redacted]	[redacted]
3			1,934,940	[redacted]	[redacted]
4			2,631,136	737,709,000	740,340,136
5			(12,635,042)	[redacted]	[redacted]
6			(12,635,042)	[redacted]	[redacted]
7			578,074	[redacted]	[redacted]
8			(3,859,665)	[redacted]	[redacted]
9			(3,281,591)	771,192,330	767,910,739
10			(15,916,633)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	28,339,337,805	28,339,337,805
4	Property Under Capital Leases	31,316,357	31,316,357
5	Plant Purchased or Sold		
6	Completed Construction not Classified	290,417,407	290,417,407
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	28,661,071,569	28,661,071,569
9	Leased to Others		
10	Held for Future Use	25,890,060	25,890,060
11	Construction Work in Progress	2,002,448,524	2,002,448,524
12	Acquisition Adjustments	156,468,483	156,468,483
13	Total Utility Plant (8 thru 12)	30,845,878,636	30,845,878,636
14	Accum Prov for Depr, Amort, & Depl	10,870,776,722	10,870,776,722
15	Net Utility Plant (13 less 14)	19,975,101,914	19,975,101,914
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	10,085,581,074	10,085,581,074
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	652,942,422	652,942,422
22	Total In Service (18 thru 21)	10,738,523,496	10,738,523,496
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	132,253,226	132,253,226
33	Total Accum Prov (equals 14) (22,26,30,31,32)	10,870,776,722	10,870,776,722

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
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					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 2019/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	209,604,815	299,406
4	(303) Miscellaneous Intangible Plant	760,827,206	53,832,204
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	970,432,021	54,131,610
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	92,989,902	5,142
9	(311) Structures and Improvements	1,039,610,644	19,609,447
10	(312) Boiler Plant Equipment	4,664,914,276	91,788,280
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	1,001,145,420	14,875,454
13	(315) Accessory Electric Equipment	489,701,921	4,130,116
14	(316) Misc. Power Plant Equipment	33,490,333	1,775,555
15	(317) Asset Retirement Costs for Steam Production	131,258,959	29,760,022
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	7,453,111,455	161,944,016
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	36,320,104	109,062
28	(331) Structures and Improvements	278,438,856	5,652,967
29	(332) Reservoirs, Dams, and Waterways	511,877,153	7,016,515
30	(333) Water Wheels, Turbines, and Generators	138,470,585	6,105,107
31	(334) Accessory Electric Equipment	84,803,729	1,776,898
32	(335) Misc. Power PLant Equipment	2,374,352	241,126
33	(336) Roads, Railroads, and Bridges	24,974,420	150,384
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,077,259,199	21,052,059
36	D. Other Production Plant		
37	(340) Land and Land Rights	45,432,889	5,525,956
38	(341) Structures and Improvements	229,031,081	2,574,473
39	(342) Fuel Holders, Products, and Accessories	16,188,175	29,789
40	(343) Prime Movers	2,940,730,523	658,563,917
41	(344) Generators	478,615,156	54,099,740
42	(345) Accessory Electric Equipment	329,144,345	1,663,251
43	(346) Misc. Power Plant Equipment	15,924,321	206,595
44	(347) Asset Retirement Costs for Other Production	16,855,215	2,241,187
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	4,071,921,705	724,904,908
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	12,602,292,359	907,900,983

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
279,935			209,624,286		3
8,400,900			806,258,510		4
8,680,835			1,015,882,796		5
					6
					7
1,195			92,993,849		8
2,766,408			1,056,453,683		9
99,798,438		642,560	4,657,546,678		10
					11
7,587,767			1,008,433,107		12
754,642		-642,560	492,434,835		13
1,003,403			34,262,485		14
	-1,912,783		159,106,198		15
111,911,853	-1,912,783		7,501,230,835		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			36,429,166		27
2,511,751		-1,588	281,578,484		28
1,038,291		1,588	517,856,965		29
676,327			143,899,365		30
243,878			86,336,749		31
38,206			2,577,272		32
87,512			25,037,292		33
					34
4,595,965			1,093,715,293		35
					36
			50,958,845		37
60,091			231,545,463		38
-48			16,218,012		39
802,342,896			2,796,951,544		40
34,598,666			498,116,230		41
5,691,712			325,115,884		42
			16,130,916		43
			19,096,402		44
842,693,317			3,954,133,296		45
959,201,135	-1,912,783		12,549,079,424		46

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	272,900,490	9,643,723
49	(352) Structures and Improvements	275,874,995	8,107,097
50	(353) Station Equipment	2,265,701,408	20,786,559
51	(354) Towers and Fixtures	1,301,155,918	6,284,080
52	(355) Poles and Fixtures	960,420,522	58,083,941
53	(356) Overhead Conductors and Devices	1,253,499,035	37,297,336
54	(357) Underground Conduit	3,520,058	328,768
55	(358) Underground Conductors and Devices	8,035,354	-1,070,700
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)	6,353,044,980	139,460,804
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	64,555,204	774,777
61	(361) Structures and Improvements	120,762,525	4,312,286
62	(362) Station Equipment	1,043,475,099	45,188,274
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,220,758,561	54,673,840
65	(365) Overhead Conductors and Devices	774,459,766	35,931,593
66	(366) Underground Conduit	385,158,148	15,846,482
67	(367) Underground Conductors and Devices	898,121,842	40,026,257
68	(368) Line Transformers	1,390,837,792	52,469,821
69	(369) Services	818,443,527	43,705,175
70	(370) Meters	229,675,682	43,363,562
71	(371) Installations on Customer Premises	8,806,482	60,744
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	62,888,188	1,205,599
74	(374) Asset Retirement Costs for Distribution Plant	1,344,766	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	7,019,287,582	337,558,410
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	21,540,621	2,075,036
87	(390) Structures and Improvements	250,401,291	10,349,685
88	(391) Office Furniture and Equipment	88,315,352	5,850,337
89	(392) Transportation Equipment	117,676,889	6,499,183
90	(393) Stores Equipment	14,919,759	509,554
91	(394) Tools, Shop and Garage Equipment	63,668,918	3,394,734
92	(395) Laboratory Equipment	34,874,025	1,372,258
93	(396) Power Operated Equipment	191,826,835	7,260,916
94	(397) Communication Equipment	482,950,536	22,787,545
95	(398) Miscellaneous Equipment	8,268,735	555,298
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,274,442,961	60,654,546
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)	1,276,337,537	60,654,546
100	TOTAL (Accounts 101 and 106)	28,221,394,479	1,499,706,353
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)	28,221,394,479	1,499,706,353

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
1,177,104		-3,205	281,363,904		48
195,048			283,787,044		49
7,217,060		5,800	2,279,276,707		50
367			1,307,439,631		51
2,803,453			1,015,701,010		52
2,495,267		-1,273,814	1,287,027,290		53
			3,848,826		54
		1,273,814	8,238,468		55
			11,937,200		56
					57
13,888,299		2,595	6,478,620,080		58
					59
			65,329,981		60
78,021			124,996,790		61
2,843,740		-5,800	1,085,813,833		62
					63
7,515,344			1,267,917,057		64
3,567,340			806,824,019		65
1,873,244			399,131,386		66
3,057,194			935,090,905		67
10,252,293			1,433,055,320		68
1,256,072			860,892,630		69
27,931,630			245,107,614		70
65,052			8,802,174		71
					72
1,754,844			62,338,943		73
			1,344,766		74
60,194,774		-5,800	7,296,645,418		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			23,615,657		86
2,817,620		3,249	257,936,605		87
22,029,953		-53,009	72,082,727		88
5,033,950		90,144	119,232,266		89
559,940		89,347	14,958,720		90
3,104,812		-393,726	63,565,114		91
1,388,394		101,810	34,959,699		92
8,023,983		-101,775	190,961,993		93
4,050,446		112,721	501,800,356		94
455,491		151,239	8,519,781		95
47,464,589			1,287,632,918		96
			1,854,828		97
			39,748		98
47,464,589			1,289,527,494		99
1,089,429,632	-1,912,783	-3,205	28,629,755,212		100
					101
					102
					103
1,089,429,632	-1,912,783	-3,205	28,629,755,212		104

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)	$12,602,292,359
Less: (317) Asset Retirement Costs for Steam Production(1)	15(b)	131,258,959
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)	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.: 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)	$12,549,079,424
Less: (317) Asset Retirement Costs for Steam Production(1)	15(g)	159,106,198
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)	19,096,402
Revised TOTAL Production Plant		$12,370,876,824

(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.: 55 Column: c

The credit represents reimbursements of settlement fees for contracted work performed, return of materials and supplies to inventory and allocated overhead credits.

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)	$ 7,019,287,582
Less: (374) Asset Retirement Costs for Distribution Plant(1)	74(b)	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.: 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)	$ 7,296,645,418
Less: (374) Asset Retirement Costs for Distribution Plant(1)	74(g)	1,344,766
Revised TOTAL Distribution Plant		$ 7,295,300,652

(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 399.21, 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)	$ 1,276,337,537
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		$ 1,274,442,961

(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.: 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)	$ 1,289,527,494
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		$ 1,287,632,918

(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)
TOTAL Intangible Plant	5(b)	$ 970,432,021
Revised TOTAL Production Plant(1)		12,454,178,185
TOTAL Transmission Plant	58(b)	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(b)	-
(Less) (102) Electric Plant Sold	102(b)	-
(103) Experimental Plant Unclassified	103(b)	-
Revised TOTAL Electric Plant in Service		$28,070,040,963

(1) Refer to footnote on page 204, line no. 46, column (b)
(2) Refer to footnote on page 204, line no. 75, column (b)
(3) 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)	$ 1,015,882,796
Revised TOTAL Production Plant(1)		12,370,876,824
TOTAL Transmission Plant	58(g)	6,478,620,080
Revised TOTAL Distribution Plant(2)		7,295,300,652
Revised TOTAL General Plant(3)		1,287,632,918
(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		$28,448,313,270

(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 2019/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	2027	1,173,276
6	Mountain Green Substation	2009	2026	284,996
7	Hoggard Substation	2009	2025	254,397
8	Oquirrh-Terminal 345kV Transmission Line	2009	2024	396,020
9	Bend Service Center	2010	2021	2,982,321
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	2021	683,318
15	Old Mill Substation	2012	2027	1,838,281
16	Chimney Butte-Paradise 230kV Transmission Line	2013	2026	598,457
17	Fiddlers Canyon Substation	2016	2028	1,136,587
18	Gateway Area Substation	2017	2023	3,166,188
19	Miscellaneous, each under $250,000:			912,001
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
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33				
34				
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36				
37				
38				
39				
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41				
42				
43				
44				
45				
46				
47	Total			25,890,060

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.

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	Customer Relationship Management Focused Software Upgrade	5,268,765
3	Customer Revenue, Billing and Tariff Analysis Software	3,840,009
4	Mapping System Consolidation Software	2,952,488
5	Prospect No. 3 Hydro Relicensing	2,160,095
6	Cutler Hydro Relicensing	1,632,830
7	Weber Hydro Relicensing	1,321,749
8	Computer Aided Distribution Operations System Software Upgrade	1,103,582
9	Production:	
10	TB Flats Wind Project 500 MW**	202,243,593
11	Marengo Wind Repowering**	137,446,545
12	Ekola Flats Wind Project 250 MW**	116,380,702
13	Dunlap Ranch 1 Wind Repowering**	98,993,227
14	Pryor Mountain Wind Project 240 MW	64,633,874
15	Marengo II Wind Repowering**	62,822,559
16	Foote Creek Wind Repowering**	13,141,125
17	Lewis River System Relicensing Implementation	11,347,161
18	Lake Side 2 Steam Turbine Generator Stator Replacement and Rotor Rewind	10,929,821
19	Safe Harbor Equipment Purchases	9,112,993
20	Hermiston U1 & U2 Low Pressure Evaporator and Feedwater Heater Replacement	3,777,309
21	Toketee Dam Rehabilitation Evaluation	3,397,890
22	Merwin Spillway Gate Wood Extension Replacement	3,021,694
23	Merwin Hydro Spillway Gate Hoist Platform Retrofit	2,931,193
24	Cedar Springs Wind Project 200 MW**	2,406,676
25	Jim Bridger Coal Combustion Residual Flue Gas Desulfurization Pond 4 Stage 1	1,909,696
26	Huntington Waste Water Redirect	1,823,249
27	Jim Bridger U4 Catalyst Replacement, Selective Catalytic Reduction System	1,613,117
28	Soda Hydro Spinning Reserve	1,432,093
29	Yale Dam Spillway Upgrades Evaluation	1,358,491
30	Hunter U3 East & West Waterwall Replacement	1,330,906
31	Blundell Plant and Steam Field Controls Update	1,326,346
32	Viva Naughton FERC Production Compliance	1,246,828
33	Oneida Dam Concrete Section Replacement	1,221,259
34	Wallowa Falls Relicensing Implementation	1,171,263
35	Bear River Hydro Flood and Structural Assessment Project	1,134,406
36	Blundell U2 Generator Replacement	1,064,023
37	Transmission:	
38	Aeolus - Bridger/Anticline 500kV Line**	492,989,748
39	Aeolus - Mona 500kV Line	122,483,758
40	Boardman - Hemingway 500kV Line	78,364,837
41	Populus - Hemingway 500kV Line	65,939,122
42	Anticline - Populus 500kV Line	46,204,915
43	TOTAL	2,002,448,524

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Vantage - Pomona Heights 230kV Line	45,232,734
2	Q712 Cedar Springs Wind 1**	32,629,477
3	Q707 TB Flats 1**	29,115,009
4	Vitesse - Facebook 60 MW Load Addition	20,233,158
5	Goshen - Sugarmill - Rigby 161kV Line	16,302,631
6	Oquirrh - Terminal 345kV Line	15,087,754
7	Windstar - Shirley Basin 230kV Line	13,808,847
8	Goshen Substation Install 3rd 345 - 161kV 700 MVA Transformer TPL	8,629,805
9	Sams Valley New 500 - 230kV Substation	8,374,239
10	Rexburg Substation - Install 161kV Source from Rigby	7,431,750
11	Populus - Terminal 345kV Line - Staker Relocation	5,941,576
12	Jordanelle - Midway 138kV Line	5,109,490
13	Spanish Fork Substation 345 - 138kV Transformer Upgrade TPL	3,425,131
14	Q737 Cove Mountain Solar 2, LLC	3,152,267
15	Q641 Cove Mountain Solar	2,707,709
16	Bull River to Saratoga Rebuild for Network Customer	1,968,620
17	Outlook Substation: Replace Transformer	1,961,182
18	State Prison at Salt Lake City 8 MW Transmission Load	1,773,320
19	El Monte Substation Expansion	1,651,357
20	Hunter U2 Generator Step-Up Transformer Replacement	1,282,453
21	90th South Substation Bus Tie Breaker Upgrade	1,277,862
22	Yreka Substation 115 - 69kV Transformer Addition	1,255,177
23	Siphon Tap - Pingree Junction 138kV Line Reconductor	1,224,580
24	Idaho Power: Borah-Adelaide-Midpoint #1: Replace Wood Poles with Steel	1,062,514
25	Dry Gulch Substation Replace 115 - 69kV Fixed-Ratio Transformer	1,006,829
26	Distribution:	
27	Utah Advanced Metering Infrastructure	16,621,150
28	Boise White Paper, LLC Interconnect Load Addition	8,743,465
29	Naples New 138 - 12.5kV Substation TPL	6,774,948
30	Draper Increase Capacity and Convert to 138kV	5,326,569
31	Lassen Substation - New Substation	4,341,869
32	CPC International Apple Co. Load Addition	3,537,945
33	Kennedy Substation Convert to Distribution	2,588,767
34	Idaho Advanced Metering Infrastructure	2,248,800
35	Murphy Brown LLC - 15.29 kW Load	1,020,686
36	General:	
37	Monarch PAC6 Upgrade and Hardware	2,174,321
38	Replacement of DMX Fiber Optic Communications Infrastructure/Equip - Southern Oregon	1,161,601
39		
40	Miscellaneous Projects each under $1,000,000	132,782,995
41		
42	** Energy Vision 2020 projects	
43	TOTAL	2,002,448,524

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	10,291,136,026	10,291,136,026		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	879,989,526	879,989,526		
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):	22,051,799	22,051,799		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	902,041,325	902,041,325		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	1,080,709,354	1,080,709,354		
13	Cost of Removal	69,673,217	69,673,217		
14	Salvage (Credit)	3,872,248	3,872,248		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	1,146,510,323	1,146,510,323		
16	Other Debit or Cr. Items (Describe, details in footnote):	38,914,046	38,914,046		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	10,085,581,074	10,085,581,074		

Section B. Balances at End of Year According to Functional Classification

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)
20	Steam Production	3,818,512,531	3,818,512,531		
21	Nuclear Production				
22	Hydraulic Production-Conventional	452,937,506	452,937,506		
23	Hydraulic Production-Pumped Storage				
24	Other Production	530,489,089	530,489,089		
25	Transmission	1,863,152,997	1,863,152,997		
26	Distribution	2,926,917,777	2,926,917,777		
27	Regional Transmission and Market Operation				
28	General	493,571,174	493,571,174		
29	TOTAL (Enter Total of lines 20 thru 28)	10,085,581,074	10,085,581,074		

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	$ 245,756
Account 182.3, Other regulatory assets or Account 254, Other regulatory liabilities: asset retirement obligations asset depreciation	9,036,800
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	(560,206)
Transportation depreciation charged to operations and maintenance expense and construction work in progress based on usage activity	16,386,376
Account 503, Steam from other sources: Blundell depreciation	2,024,541
Total Other Accounts	$ 22,051,799

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	$ 11,194,379
Other items include:	27,719,667
- Recovery from third parties for asset relocations and damaged property	
- Insurance recoveries	
- Adjustments of reserve related to electric plant sold and/or purchased	
- Reclassifications from electric plant	
Total Other Debit or Cr. Items	$ 38,914,046

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)	$ 3,818,512,531
Less: Asset retirement obligations related cost components(1)		68,821,875
Revised Steam Production		$ 3,749,690,656

(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)	$ 452,937,506
Less: Asset retirement obligations related cost components(1)		2,675,845
Revised Hydraulic Production - Conventional		$ 450,261,661

(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)	$ 530,489,089
Less: Asset retirement obligations related cost components(1)		(954,086)
Revised Other Production		$ 531,443,175

(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)	$ 2,926,917,777
Less: Asset retirement obligations related cost components(1)		972,066
Revised Distribution		$ 2,925,945,711

(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)	$ 493,571,174
Less: Asset retirement obligations related cost components(1)		(184,898)
Revised General		$ 493,756,072

(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)		$ 3,749,690,656
Nuclear Production	21(c)	-
Revised Hydraulic Production - Conventional(2)		450,261,661
Hydraulic Production - Pumped Storage	23(c)	-
Revised Other Production(3)		531,443,175
Revised Transmission	25(c)	1,863,152,997
Revised Distribution(4)		2,925,945,711
Regional Transmission and Market Operation	27(c)	-
Revised General(5)		493,756,072
Revised TOTAL		$10,014,250,272

(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. 26, column (c)
(5) 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 2019/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			96,380,655
5	SUBTOTAL			144,340,656
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			8,017,743
22	SUBTOTAL			14,055,743
23				
24	Fossil Rock Fuels, LLC	2011		
25	Paid-in Capital			25,001,770
26	Undistributed Subsidiary Earnings			847
27	SUBTOTAL			25,002,617
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 76,336,772		TOTAL	183,401,017

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1		2
		47,960,000		3
19,412,436		115,793,091		4
19,412,436		163,753,092		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
1,754,143		9,771,559		21
1,754,143		15,809,559		22
				23
				24
		22,336,770		25
2,396,732		579		26
2,396,732		22,337,349		27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
23,563,311		201,902,001		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.: 21 Column: g

During the year ended December 31, 2019, Trapper Mining Inc., a subsidiary of PacifiCorp, paid a distribution of $327 to PacifiCorp.

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

During the year ended December 31, 2019, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, returned $2,665,000 of capital to PacifiCorp.

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

During the year ended December 31, 2019, Fossil Rock Fuels, LLC, a wholly owned subsidiary of PacifiCorp, paid distributions of $2,397,000 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)	179,588,705	150,404,985	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)	161,139,297	162,913,741	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	63,541,336	67,226,405	Electric
8	Transmission Plant (Estimated)	786,256	852,235	Electric
9	Distribution Plant (Estimated)	12,201,122	13,010,416	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	26,420	20,127	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	237,694,431	244,022,924	
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)	417,283,136	394,427,909	

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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/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)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	936,977.00		156,646.00	
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	25,625.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	911,352.00		156,646.00	
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 2019/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.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
156,646.00		156,647.00		4,072,755.00		5,479,671.00		1
								2
								3
				156,644.00		156,644.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						25,625.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
156,646.00		156,647.00		4,229,399.00		5,610,690.00		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 2019/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	Q2469	181	561.6		
3	Q2517	149	561.6		
4	Q2518	1,267	561.6		
5	Q2527	149	561.6		
6	Q2528	149	561.6		
7	Q2574	14,846	561.6		
8	Q2578	972	561.6	972	456
9	Q2587	2,512	561.6	2,512	456
10	Q2588	1,071	561.6		
11	Q2591	447	561.6		
12	Q2592	298	561.6		
13	Q2594	149	561.6	149	456
14	Q2599	21,446	561.6		
15	Q2602	1,531	561.6	1,531	456
16	Q2612	4,987	561.6	4,987	456
17	Q2629	1,877	561.6		
18	Q2651	380	561.6	380	456
19	Q2652	809	561.6	809	456
20	Q2687	149	561.6		
21	**Generation Studies**				
22	GIQ0409	1,615	561.7	1,615	456
23	GIQ0650	346	561.7	346	456
24	GIQ0687	9,103	561.7	9,103	456
25	GIQ0707	1,526	561.7	1,526	456
26	GIQ0708	1,217	561.7	1,217	456
27	GIQ0712	11,087	561.7	11,087	456
28	GIQ0713	5,668	561.7	5,668	456
29	GIQ0715	270	561.7	270	456
30	GIQ0718	9,013	561.7	9,013	456
31	GIQ0719	643	561.7	643	456
32	GIQ0721	76	561.7	76	456
33	GIQ0737	37	561.7	37	456
34	GIQ0738	2,918	561.7	2,918	456
35	GIQ0739	15,313	561.7	15,313	456
36	GIQ0741	115	561.7	115	456
37	GIQ0745	4,740	561.7	4,740	456
38	GIQ0763	308	561.7	308	456
39	GIQ0777	423	561.7	423	456
40	GIQ0778	346	561.7	346	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	Q2702	1,795	561.6		
3	Order 45045642	(10,559)	561.6	(10,559)	456
4	Pre-Application Studies - East	37,718	561.6		
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0783	5,616	561.7	5,616	456
23	GIQ0784	115	561.7	115	456
24	GIQ0785	803	561.7	803	456
25	GIQ0786	312	561.7	312	456
26	GIQ0787	2,349	561.7	2,349	456
27	GIQ0788	1,443	561.7	1,443	456
28	GIQ0789	1,462	561.7	1,462	456
29	GIQ0792	421	561.7	421	456
30	GIQ0799	5,540	561.7	5,540	456
31	GIQ0801	2,955	561.7	2,955	456
32	GIQ0802	4,215	561.7	4,215	456
33	GIQ0804	4,174	561.7	4,174	456
34	GIQ0805	26,842	561.7	26,842	456
35	GIQ0807	5,049	561.7	5,049	456
36	GIQ0811	2,397	561.7	2,397	456
37	GIQ0815	214	561.7	214	456
38	GIQ0820	21,612	561.7		
39	GIQ0821	29,715	561.7		
40	GIQ0822	11,991	561.7		

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**	[redacted]			
2					
3					
4					
5					
6					
7					
8					
9					
10					
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21	**Generation Studies**	[redacted]			
22	GIQ0823	19,537	561.7		
23	GIQ0824	15,963	561.7	15,963	456
24	GIQ0825	4,675	561.7	4,675	456
25	GIQ0835	5,039	561.7	5,039	456
26	GIQ0836	837	561.7	837	456
27	GIQ0838	1,425	561.7	1,425	456
28	GIQ0839	307	561.7	307	456
29	GIQ0840	1,093	561.7	1,093	456
30	GIQ0846	616	561.7	616	456
31	GIQ0849	192	561.7	192	456
32	GIQ0850	4,898	561.7	4,898	456
33	GIQ0853	375	561.7	375	456
34	GIQ0855	3,721	561.7	3,721	456
35	GIQ0858	2,624	561.7		
36	GIQ0859	5,472	561.7		
37	GIQ0860	1,987	561.7		
38	GIQ0861	3,058	561.7		
39	GIQ0862	9,714	561.7	9,714	456
40	GIQ0863	149	561.7		

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	GIQ0864	19	561.7	19	456
23	GIQ0865	19	561.7	19	456
24	GIQ0867	115	561.7	115	456
25	GIQ0868	6,475	561.7	6,475	456
26	GIQ0871	77	561.7	77	456
27	GIQ0872	38	561.7	38	456
28	GIQ0876	7,878	561.7		
29	GIQ0877	103	561.7	103	456
30	GIQ0883	38	561.7	38	456
31	GIQ0898	154	561.7	154	456
32	GIQ0905	458	561.7	458	456
33	GIQ0906	7,735	561.7	7,735	456
34	GIQ0907	7,815	561.7	7,815	456
35	GIQ0915	173	561.7	173	456
36	GIQ0916	135	561.7	135	456
37	GIQ0917	135	561.7	135	456
38	GIQ0918	550	561.7		
39	GIQ0919	193	561.7		
40	GIQ0920	38	561.7	38	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	GIQ0925	38	561.7	38	456
23	GIQ0933	58	561.7	58	456
24	GIQ0934	19	561.7	19	456
25	GIQ0938	77	561.7	77	456
26	GIQ0940	499	561.7	499	456
27	GIQ0941	350	561.7	350	456
28	GIQ0947	230	561.7	230	456
29	GIQ0948	191	561.7	191	456
30	GIQ0949	153	561.7	153	456
31	GIQ0953	3,411	561.7	3,411	456
32	GIQ0955	(51)	561.7	(51)	456
33	GIQ0957	272	561.7	272	456
34	GIQ0958	154	561.7	154	456
35	GIQ0959	77	561.7	77	456
36	GIQ0961	77	561.7	77	456
37	GIQ0965	77	561.7	77	456
38	GIQ0968	154	561.7	154	456
39	GIQ0971	(13)	561.7	(13)	456
40	GIQ0974	7,780	561.7	7,780	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	GIQ0976	77	561.7	77	456
23	GIQ0995	115	561.7	115	456
24	GIQ0996	38	561.7	38	456
25	GIQ0999	116	561.7	116	456
26	GIQ1003	1,559	561.7	1,559	456
27	GIQ1007	317	561.7	317	456
28	GIQ1008	481	561.7	481	456
29	GIQ1009	4,123	561.7	4,123	456
30	GIQ1012	138	561.7	138	456
31	GIQ1014	77	561.7	77	456
32	GIQ1019	568	561.7	568	456
33	GIQ1026	72	561.7		
34	GIQ1027	77	561.7	77	456
35	GIQ1028	58	561.7	58	456
36	GIQ1029	4,402	561.7	4,402	456
37	GIQ1031	58	561.7	58	456
38	GIQ1032	58	561.7	58	456
39	GIQ1033	58	561.7	58	456
40	GIQ1034	38	561.7	38	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 2019/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	GIQ1035	96	561.7	96	456
23	GIQ1036	19	561.7	19	456
24	GIQ1037	77	561.7		
25	GIQ1038	114	561.7	114	456
26	GIQ1039	37	561.7	37	456
27	GIQ1043	1,045	561.7	1,045	456
28	GIQ1045	38	561.7	38	456
29	GIQ1046	58	561.7	58	456
30	GIQ1051	19	561.7	19	456
31	GIQ1052	38	561.7	38	456
32	GIQ1053	58	561.7	58	456
33	GIQ1054	58	561.7	58	456
34	GIQ1055	3,217	561.7	3,217	456
35	GIQ1057	19	561.7	19	456
36	GIQ1058	19	561.7	19	456
37	GIQ1059	19	561.7	19	456
38	GIQ1060	19	561.7	19	456
39	GIQ1061	19	561.7	19	456
40	GIQ1063	1,631	561.7	1,631	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 2019/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	GIQ1065	115	561.7	115	456
23	GIQ1066	19	561.7	19	456
24	GIQ1067	19	561.7	19	456
25	GIQ1068	96	561.7	96	456
26	GIQ1070	102	561.7	102	456
27	GIQ1071	19	561.7	19	456
28	GIQ1072	19	561.7	19	456
29	GIQ1073	71	561.7	71	456
30	GIQ1074	148	561.7	148	456
31	GIQ1075	419	561.7	419	456
32	GIQ1076	143	561.7	143	456
33	GIQ1077	267	561.7	267	456
34	GIQ1078	228	561.7	228	456
35	GIQ1079	14,992	561.7	14,992	456
36	GIQ1080	157	561.7	157	456
37	GIQ1081	72	561.7	72	456
38	GIQ1083	259	561.7	259	456
39	GIQ1084	363	561.7	363	456
40	GIQ1085	256	561.7	256	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 2019/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	GIQ1086	4,002	561.7	4,002	456
23	GIQ1087	448	561.7	448	456
24	GIQ1088	1,191	561.7	1,191	456
25	GIQ1089	226	561.7	226	456
26	GIQ1090	226	561.7	226	456
27	GIQ1091	264	561.7	264	456
28	GIQ1092	1,639	561.7	1,639	456
29	GIQ1093	1,164	561.7	1,164	456
30	GIQ1094	931	561.7	931	456
31	GIQ1095	782	561.7	782	456
32	GIQ1096	1,373	561.7	1,373	456
33	GIQ1097	1,720	561.7	1,720	456
34	GIQ1098	1,416	561.7	1,416	456
35	GIQ1099	1,586	561.7	1,586	456
36	GIQ1100	1,328	561.7	1,328	456
37	GIQ1101	931	561.7	931	456
38	GIQ1102	1,086	561.7	1,086	456
39	GIQ1103	1,882	561.7	1,882	456
40	GIQ1104	1,291	561.7	1,291	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	GIQ1105	1,528	561.7	1,528	456
23	GIQ1106	1,381	561.7	1,381	456
24	GIQ1107	231	561.7	231	456
25	GIQ1108	1,469	561.7	1,469	456
26	GIQ1109	1,327	561.7	1,327	456
27	GIQ1110	1,599	561.7	1,599	456
28	GIQ1111	741	561.7	741	456
29	GIQ1112	1,012	561.7	1,012	456
30	GIQ1113	5,431	561.7	5,431	456
31	GIQ1114	6,964	561.7	6,964	456
32	GIQ1115	347	561.7	347	456
33	GIQ1116	1,383	561.7	1,383	456
34	GIQ1117	2,096	561.7	2,096	456
35	GIQ1118	1,865	561.7	1,865	456
36	GIQ1119	1,014	561.7	1,014	456
37	GIQ1120	1,420	561.7	1,420	456
38	GIQ1121	1,034	561.7	1,034	456
39	GIQ1122	58	561.7	58	456
40	GIQ1123	1,578	561.7	1,578	456

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	GIQ1124	996	561.7	996	456
23	GIQ1125	561	561.7	561	456
24	GIQ1126	1,241	561.7	1,241	456
25	GIQ1127	1,457	561.7	1,457	456
26	GIQ1128	792	561.7	792	456
27	GIQ1129	1,270	561.7	1,270	456
28	GIQ1130	1,655	561.7	1,655	456
29	GIQ1131	1,552	561.7	1,552	456
30	GIQ1132	1,456	561.7	1,456	456
31	GIQ1133	977	561.7	977	456
32	GIQ1134	662	561.7	662	456
33	GIQ1135	959	561.7	959	456
34	GIQ1136	671	561.7	671	456
35	GIQ1137	538	561.7	538	456
36	GIQ1138	600	561.7	600	456
37	GIQ1139	447	561.7	447	456
38	GIQ1140	5,622	561.7	5,622	456
39	GIQ1141	250	561.7	250	456
40	GIQ1142	250	561.7	250	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	GIQ1143	1,472	561.7	1,472	456
23	GIQ1144	1,399	561.7	1,399	456
24	GIQ1145	1,023	561.7	1,023	456
25	GIQ1146	1,245	561.7	1,245	456
26	GIQ1147	1,729	561.7	1,729	456
27	GIQ1148	1,391	561.7	1,391	456
28	GIQ1149	1,427	561.7	1,427	456
29	GIQ1150	752	561.7	752	456
30	GIQ1151	980	561.7	980	456
31	GIQ1152	1,559	561.7	1,559	456
32	GIQ1153	1,001	561.7	1,001	456
33	GIQ1154	472	561.7	472	456
34	GIQ1155	509	561.7	509	456
35	GIQ1156	435	561.7	435	456
36	GIQ1157	1,504	561.7	1,504	456
37	GIQ1158	3,973	561.7	3,973	456
38	GIQ1159	1,721	561.7	1,721	456
39	GIQ1160	1,359	561.7	1,359	456
40	GIQ1161	1,190	561.7	1,190	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	GIQ1162	616	561.7	616	456
23	GIQ1163	674	561.7	674	456
24	GIQ1164	515	561.7	515	456
25	GIQ1165	1,660	561.7	1,660	456
26	GIQ1166	1,111	561.7	1,111	456
27	GIQ1167	789	561.7	789	456
28	GIQ1168	1,232	561.7	1,232	456
29	GIQ1169	1,475	561.7	1,475	456
30	GIQ1170	1,320	561.7	1,320	456
31	GIQ1171	1,018	561.7	1,018	456
32	GIQ1172	1,741	561.7	1,741	456
33	GIQ1173	1,139	561.7	1,139	456
34	GIQ1174	1,480	561.7	1,480	456
35	GIQ1175	1,493	561.7	1,493	456
36	GIQ1176	1,160	561.7	1,160	456
37	GIQ1177	626	561.7	626	456
38	GIQ1178	774	561.7	774	456
39	GIQ1179	417	561.7	417	456
40	GIQ1180	554	561.7	554	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	GIQ1181	466	561.7	466	456
23	GIQ1182	1,020	561.7	1,020	456
24	GIQ1183	1,047	561.7	1,047	456
25	GIQ1184	250	561.7	250	456
26	GIQ1186	1,383	561.7	1,383	456
27	GIQ1188	583	561.7	583	456
28	GIQ1189	907	561.7	907	456
29	GIQ1190	400	561.7	400	456
30	GIQ1191	58	561.7	58	456
31	Pre-Application Studies - East	12,578	561.7	12,578	456
32	Pre-Application Studies - West	7,058	561.7	7,058	456
33	Customer Studies Accrual	44	561.7		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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 - WY	8,587,281	9,236,451	908	9,803,790	8,019,942
2	Irrigation Load Control - OR	96,833	196,244	908	134,304	158,773
3	Deferred Excess Net Power Costs - CA	6,009,612	2,635,221	555	2,662,501	5,982,332
4	Deferred Excess Net Power Costs - ID	18,176,983	18,565,011	555	11,701,152	25,040,842
5	Deferred Excess Net Power Costs - OR		2,980,283			2,980,283
6	Deferred Excess Net Power Costs - UT	30,371,764	32,751,833	182.3,555	10,095,099	53,028,498
7	Deferred Excess Net Power Costs - WY	5,512,772	13,582,402	555	319,363	18,775,811
8	Deferred Excess RECs in Rates - UT	1,038,542	20,994	456	1,059,536	
9	Deferred Excess RECs in Rates - WY	764,224	15,096	456	606,758	172,562
10	Solar ITC Basis Adjustment Regulatory Asset	36,250	422	282,283	2,328	34,344
11	Pension	442,471,226	1,625,235		22,230,289	421,866,172
12	Other Postretirement	5,713,302	291,300		6,004,602	
13	Postemployment Costs	862,273			413,204	449,069
14	Powerdale Decommissioning - ID (10)	51,728		407.3	23,801	27,927
15	Carbon Plant Regulatory Asset - ID (6)	957,276		403	478,639	478,637
16	Carbon Plant Regulatory Asset - UT (6)	6,889,283		403	3,444,641	3,444,642
17	Carbon Plant Regulatory Asset - WY (6)	2,316,375		403	1,158,188	1,158,187
18	Carbon Plant Inventory Regulatory Asset	3,118,823				3,118,823
19	Cholla Plant Unit No. 4 Regulatory Asset		25,487,600			25,487,600
20	Depreciation Study Deferral - UT (17)	1,600,540		403	128,043	1,472,497
21	Depreciation Study Deferral - WY (17)	5,527,386		403	442,191	5,085,195
22	Generating Plant Liquidated Damages - UT	525,000		557	35,000	490,000
23	Generating Plant Liquidated Damages - WY	1,190,128		557	54,288	1,135,840
24	Klamath Hydroelectric Relicensing Costs - UT (10)	15,672,342	593,474	404	4,263,002	12,002,814
25	Washington Colstrip Unit No. 3 (22)	108,755		456	52,188	56,567
26	Environmental Costs (10)	82,555,814	8,119,799		5,328,927	85,346,686
27	Asset Retirement Obligations Regulatory Difference	118,653,129	21,553,131			140,206,260
28	Unamortized Contract Values	78,751,716		242	18,587,574	60,164,142
29	Unrealized Loss on Derivative Contracts	95,777,883		175,244	33,679,611	62,098,272
30	Solar Feed-In Tariff Deferral - OR (1)	5,125,795	5,298,111	555,908	4,789,865	5,634,041
31	Oregon Community Solar Program		604,150	908	106,426	497,724
32	Solar Incentive Subscriber Program - UT	1,663,323	199,268	908	137,691	1,724,900
33	Renewable Portfolio Standards Compliance - OR (1)	115,099	520,569	555	635,668	
34	Renewable Portfolio Standards Compliance - WA (1)	47,829	161,153	555	161,079	47,903
35	Protocol - MSP Deferral - ID	150,000	150,000			300,000
36	Protocol - MSP Deferral - UT	8,800,000	4,400,000			13,200,000
37	Protocol - MSP Deferral - WY	2,399,998	1,600,002			4,000,000
38	Deferred Intervenor Funding Grants - CA	41,995	1,754			43,749
39	Deferred Intervenor Funding Grants - ID	66,865				66,865
40	Deferred Intervenor Funding Grants - OR	926,951	569,849			1,496,800
41	Catastrophic Event Regulatory Asset - CA (2)	2,179,411	342,609	924	1,468,918	1,053,102
42	Alternative Rate for Energy (CARE) - CA	281,623		142	271,958	9,665
43	Washington Low Income Program		974,878			974,878

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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 - ID	493,494	1,383,907	501	1,499,231	378,170
2	Deferred Overburden Cost - WY	1,388,565	3,893,960	501	4,218,452	1,064,073
3	BPA Balancing Account - OR	7,129,334	1,416,010			8,545,344
4	BPA Balancing Account - WA		197,289			197,289
5	Property Sales Balancing Account - OR	1,084,466	795,352	421.1,501	937,095	942,723
6	Property Insurance Reserve - OR	3,053,229	14,662,642	924	7,068,568	10,647,303
7	Misc. Regulatory Assets/Liabilities - OR	265,765	26,168			291,933
8	Depreciation Deferral - WA	6,648		254	6,648	
9	Utah Mine Disposition	137,874,223	3,071,473		16,037,465	124,908,231
10	Preferred Stock Redemption Loss - UT (10)	429,848		407.3	82,531	347,317
11	Preferred Stock Redemption Loss - WA (10)	68,808		407.3	13,318	55,490
12	Preferred Stock Redemption Loss - WY (10)	148,133		407.3	28,442	119,691
13	Mobile Home Park Conversion - CA	198,710	4,500			203,210
14	Transportation Electrification Program - OR	48,792	768,596			817,388
15	Transportation Electrification Program - WA		137,015			137,015
16	Wildfire Mitigation Plan - CA		3,173,502			3,173,502
17						
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44	**TOTAL :**	1,107,326,144	182,007,253		170,172,374	1,119,161,023

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

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

Schedule Page: 232 Line No.: 4 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.: 8 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.: 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.: 11 Column: a

Weighted average remaining life being amortized is 21 years. Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

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

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: 232 Line No.: 13 Column: a

Weighted average remaining life is five years.

Schedule Page: 232 Line No.: 13 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.: 22 Column: a

Weighted average remaining life is 14 years.

Schedule Page: 232   Line No.: 23   Column: a

Weighted average remaining life is 23 years.

Schedule Page: 232   Line No.: 26   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
Account 935, Maintenance of general plant

Schedule Page: 232   Line No.: 28   Column: a

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

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

Weighted average remaining life is three years.

Schedule Page: 232.1   Line No.: 9   Column: a

Weighted average remaining life is approximately three years for closure costs incurred to date considered probable of recovery.

Schedule Page: 232.1   Line No.: 9   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	Lacomb Irrigation (24)	140,970		557	45,720	95,250
2	Bogus Creek (41)	870,320		557	41,280	829,040
3	Mead Phoenix Availability and					
4	Transmission Charge	10,434,083		565	586,611	9,847,472
5	TGS Buyout (23)	16,763		557	15,473	1,290
6	Point-to-Point Transmission	979,032	150,000	131	67,560	1,061,472
7	Hermiston Swap (40)	3,018,937		557	171,693	2,847,244
8	Deferred Coal Costs - Wyodak					
9	Settlement (22)	1,340,726		501	335,182	1,005,544
10	LT Lease Commissions Prepaid	106,895		931	39,385	67,510
11	Lake Side Maintenance Prepaid	21,681,927	8,090,310			29,772,237
12	Lake Side 2 Maintenance Prepaid	8,719,256	5,380,266			14,099,522
13	Chehalis Maintenance Prepaid	12,812,284	4,878,970			17,691,254
14	Currant Creek Maint. Prepaid	11,103,203	5,904,154			17,007,357
15	Seven Mile Hill Maint. Prepaid		679,935			679,935
16	Seven Mile Hill II Main Prepaid		133,927			133,927
17	Lease Incentives		134,335	454	69,087	65,248
18	Credit Agreement Costs	1,849,374	535,000	427,431	701,013	1,683,361
19	PCRB LOC/SBBPA Costs	644		427	644	
20	PCRB Mode Conversion Costs	285,232	267,544	427	118,672	434,104
21	'94 Series Restruct. Costs (16)	342,821		427	58,769	284,052
22	Deferred S-3 Shelf Regis. Costs	313,467		181	149,966	163,501
23	BPA LT Transmission Prepaid	1,371,194	100,536	565	973,234	498,496
24	Emission Reduction Credits	306,510				306,510
25	Unamortized Contract Values	7,290,380	3,811,085			11,101,465
26	Sales of Electric Utility					
27	Facilities & Properties	61,240	100	539	100	61,240
28	IT Licenses and Maint. Prepaid	128,680		921	53,680	75,000
29	Deferred Software					
30	Implementation Costs		734,762			734,762
31	Prepaid Coal Costs - Wyodak		3,646,923			3,646,923
32	Other Deferred Charges	2,071	339	181	1,196	1,214
33						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	83,176,009				114,194,930

Schedule Page: 233 Line No.: 4 Column: a

The amortization period will end when the Cholla Plant, Unit 4 has been retired from service and all costs of terminating Unit 4 have been paid.

Schedule Page: 233 Line No.: 10 Column: a

The weighted average remaining life is two years.

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

The weighted average remaining life is two years.

Schedule Page: 233 Line No.: 18 Column: a

The weighted average remaining life is three years.

Schedule Page: 233 Line No.: 20 Column: a

The weighted average remaining life is five 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 2019/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	91,494,740	82,774,477
3	Derivative contracts and unamortized contract values	45,186,081	33,070,119
4	State carryforwards	76,749,053	70,298,021
5	Asset retirement obligations	53,101,152	60,936,151
6	Regulatory liabilities	503,204,846	475,895,161
7	Other	54,723,740	60,587,707
8	TOTAL Electric (Enter Total of lines 2 thru 7)	824,459,612	783,561,636
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)	824,459,612	783,561,636

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				
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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 2019/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
357,060,915	3,417,945,896					1
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
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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.

PacifiCorp has 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 2019/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		
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16		
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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"). During the year being reported, no capital contributions were made by BHE to PacifiCorp.

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 2019/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		
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21		
22	TOTAL	41,101,061

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221, Bonds		
2	First Mortgage Bonds:		
3	5.50% Series due January 15, 2019	350,000,000	2,515,793
4			2,292,500 D
5	3.85% Series due June 15, 2021	400,000,000	3,007,139
6			744,000 D
7	2.95% Series due February 1, 2022	350,000,000	2,424,350
8			308,000 D
9	2.95% Series due February 1, 2022	100,000,000	254,129
10			-81,000 P
11	2.95% Series due June 1, 2023	300,000,000	1,859,352
12			900,000 D
13	3.60% Series due April 1, 2024	425,000,000	3,345,164
14			255,000 D
15	3.35% Series due July 1, 2025	250,000,000	2,121,421
16			320,000 D
17	3.50% Series due June 15, 2029	400,000,000	2,134,659
18			740,000 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	8,055,275,000	88,227,487

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
01/08/2009	01/15/2019	01/08/2009	01/15/2019		802,083	3
						4
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	5
						6
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	10,325,000	7
						8
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,950,000	9
						10
06/06/2013	06/01/2023	06/06/2013	06/01/2023	300,000,000	8,850,000	11
						12
03/13/2014	04/01/2024	03/13/2014	04/01/2024	425,000,000	15,300,000	13
						14
06/19/2015	07/01/2025	06/19/2015	07/01/2025	250,000,000	8,375,000	15
						16
03/01/2019	06/15/2029	03/01/2019	06/15/2029	400,000,000	11,627,778	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
				7,705,275,000	369,853,259	33

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.00% 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	4.15% Series due February 15, 2050	600,000,000	5,149,489
8			2,790,000 D
9	8.53% Series C Medium-Term Notes due December 16, 2021	15,000,000	115,202
10	8.375% Series C Medium-Term Notes due December 31, 2021	5,000,000	38,400
11	8.26% Series C Medium-Term Notes due January 7, 2022	5,000,000	33,243
12	8.27% Series C Medium-Term Notes due January 10, 2022	4,000,000	30,594
13	8.05% Series E Medium-Term Notes due September 1, 2022	15,000,000	131,471
14	8.07% Series E Medium-Term Notes due September 9, 2022	8,000,000	70,118
15	8.12% Series E Medium-Term Notes due September 9, 2022	50,000,000	438,238
16	8.11% Series E Medium-Term Notes due September 9, 2022	12,000,000	105,177
17	8.05% Series E Medium-Term Notes due September 14, 2022	10,000,000	87,648
18	8.08% Series E Medium-Term Notes due October 14, 2022	26,000,000	208,198
19	8.08% Series E Medium-Term Notes due October 14, 2022	25,000,000	200,190
20	8.23% Series E Medium-Term Notes due January 20, 2023	5,000,000	37,914
21	8.23% Series E Medium-Term Notes due January 20, 2023	4,000,000	30,331
22			-81,560 P
23	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
24	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
25	7.23% Series F Medium-Term Notes due August 16, 2023	15,000,000	137,211
26	7.24% Series F Medium-Term Notes due August 16, 2023	30,000,000	274,423
27	6.75% Series F Medium-Term Notes due September 14, 2023	5,000,000	38,250
28	6.75% Series F Medium-Term Notes due September 14, 2023	2,000,000	15,300
29	6.72% Series F Medium-Term Notes due September 14, 2023	2,000,000	15,300
30	6.75% Series F Medium-Term Notes due October 26, 2023	20,000,000	152,326
31	6.75% Series F Medium-Term Notes due October 26, 2023	16,000,000	121,861
32	6.75% Series F Medium-Term Notes due October 26, 2023	12,000,000	91,396
33	TOTAL	8,055,275,000	88,227,487

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
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	24,681,250	5
						6
03/01/2019	02/15/2050	03/01/2019	02/15/2050	600,000,000	20,680,833	7
						8
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	9
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	10
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	11
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	12
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	13
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	14
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	15
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	16
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	17
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	18
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	19
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	20
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	21
						22
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	23
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	24
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	25
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	26
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	27
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	28
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	29
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	30
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	31
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	32
				7,705,275,000	369,853,259	33

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.71% Series G Medium-Term Notes due January 15, 2026	100,000,000	904,467
2	Subtotal - First Mortgage Bonds	7,799,000,000	82,487,227
3			
4	Pollution Control Obligations - Secured:		
5	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
6	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
7	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
8	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
9	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
10	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
11	Subtotal Pollution Control Obligations - Secured	193,750,000	4,953,665
12			
13	Pollution Control Obligations - Unsecured:		
14	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Series 1992A	9,335,000	167,524
15	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
16	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Series 1992B	6,305,000	151,908
17	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
18	Subtotal - Pollution Control Obligations - Unsecured	62,525,000	786,595
19			
20	TOTAL ACCOUNT 221	8,055,275,000	88,227,487
21			
22	Account 222, Reacquired bonds		
23			
24	Account 223, Advances from associated companies		
25			
26	Account 224, Other long-term debt		
27			
28	Long-term debt authorized but unissued		
29			
30			
31			
32			
33	TOTAL	8,055,275,000	88,227,487

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	1
				7,449,000,000	364,908,994	2
						3
						4
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	421,712	5
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	154,456	6
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	2,326,678	7
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	299,778	8
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	98,510	9
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	434,035	10
				193,750,000	3,735,169	11
						12
						13
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	182,373	14
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	438,149	15
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	123,383	16
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	465,191	17
				62,525,000	1,209,096	18
						19
				7,705,275,000	369,853,259	20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				7,705,275,000	369,853,259	33

Schedule Page: 256 Line No.: 17 Column: a

In March 2019, PacifiCorp issued $400 million of its 3.50% First Mortgage Bonds due June 2029. State authorizations for this issuance were as follows:

- Idaho Public Utilities Commission ("IPUC") - Case No. PAC-E-18-10, Order No. 34205, dated December 7, 2018, effective through September 30, 2023.
- Oregon Public Utility Commission ("OPUC") - Docket No. UF-4304, Order No. 18-452, dated December 4, 2018.

Schedule Page: 256.1 Line No.: 7 Column: a

In March 2019, PacifiCorp issued $600 million of its 4.15% First Mortgage Bonds due February 2050. State authorizations for this issuance were 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.

Schedule Page: 256.2 Line No.: 11 Column: a

Secured by pledged first mortgage bonds registered to and held by the pollution control bond trustee generally with the same interest rates, maturity dates and redemption provisions as the pollution control bond obligations.

Schedule Page: 256.2 Line No.: 20 Column: h

Refer to Item 6 in Important Changes During the Year and Note 8 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.: 20 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.: 28 Column: a

For authorization for the issuance of long-term debt ($2.0 billion authorized; $1.0 billion available as of December 31, 2019), 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, 2019) 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, 2019) 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 2019/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)	771,192,330
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	148,901,480
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,250,045,963
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	45,923,493
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,262,853,409
26	State Tax Deductions	-40,340,612
27	Federal Tax Net Income	821,022,259
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 21.00%	172,414,674
31	Provision to Return Adjustment	4,632,010
32	Tax Reserve Changes	-34,325
33	Research and Experimentation Credits	-15,800
34	Renewable Energy Production Tax Credits	-27,792,500
35		
36	Federal Income Tax Accrual	149,204,059
37		
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Contribution in Aid of Construction	$ 114,942,433
MCI F.O.G. Wire Lease	647
Regulatory Asset - Alt Rate for Energy Program (CARE) - CA	271,958
Regulatory Asset - REC Sales Deferral - OR	115,099
Regulatory Asset - REC Sales Deferral - UT	1,038,541
Regulatory Asset - REC Sales Deferral - WY	591,662
Regulatory Asset - WA Colstrip #3	52,188
Regulatory Liability - Deferred Excess NPC - OR	5,478,956
Regulatory Liability - Depreciation Decrease - OR	1,304,531
Regulatory Liability - Excess Income Tax Deferral - CA	4,017,282
Regulatory Liability - Excess Income Tax Deferral - ID	252,190
Regulatory Liability - Excess Income Tax Deferral - OR	2,398,647
Regulatory Liability - Excess Income Tax Deferral - UT	130,948
Regulatory Liability - Excess Income Tax Deferral - WA	469,566
Regulatory Liability - OR Direct Access 5 Year Opt Out	1,917,733
Regulatory Liability - Sales of REC - OR	22,637
Regulatory Liability - Sales of REC - UT	648,864
Regulatory Liability - Sales of REC - WY	61,621
Regulatory Liability - UT Home Energy Lifeline	46,693
Regulatory Liability - WA Accel Depreciation	12,611,581
Reimbursements	2,372,063
Unearned Joint Use Power Contact Revenue	155,640
Total	$ 148,901,480

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

Particulars (Details)	Amounts
Fed/State Tax Expense	$ 58,476,068
Fed/State Tax Expense - Interest	269,756
Accrued Royalties	448,793
Accrued Vacation	139,027
Avoided Costs	67,459,367
Book Depreciation	943,502,237
Book Depreciation Allocated to Medicare and M&E	147,603
Capitalization of Test Energy	4,130,399
Capitalized Labor and Benefit Costs	7,658,810
Coal Pile Inventory Adjustment	110,446
Company Plane - Nonbusiness Use	42,810
Contra PP&E Cholla U4 Closure	25,281,533
CWIP Reserve	2,584,651
Deferred Compensation	1,449,597
Environmental Liability - Regulated	836,946
Executive Compensation - IRS Section 162(m)	160,925
FAS 112 Book Reserve - Postemployment Benefits	2,363,728
Fuel Cost Adjustment	219,302
Hermiston Swap	171,693
Hydro Relicensing Obligation	1,330,948
Injuries & Damages Reserve - OR	1,845,855
Inventory Reserve	865,878
Inventory Reserve - Cholla U4	6,106,205
Lease Liability (Operating Leases)	11,932,093
Lewis River Settlement Agreement	14,627
Liquidated Damages - Cholla U4	19,606,070
Lobbying Expenses	1,097,826
LT Incentive Plan	1,221,595
Meals and Entertainment	1,947,043
Non-deductible Fringe Benefits	478,957
Non-deductible Parking Costs	470,243
Prepaid Taxes - OPUC	52,091
Prepaid Taxes - UPSC	35,535
Prepaid Water Rights	161,250
Property Insurance Reserve - ID	113,544
Property Insurance Reserve - UT	1,104,416
Property Insurance Reserve - WY	349,810
Regulatory Asset - Asset Sales Balancing Account - OR	141,743
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 - Catastrophic Event Deferral - CA	1,126,309

Regulatory Asset - Deferred Excess NPC - CA	27,280
Regulatory Asset - Deferred Overburden Costs - ID	115,324
Regulatory Asset - Deferred Overburden Costs - WY	324,492
Regulatory Asset - Demand Side Management	187,760
Regulatory Asset - Depreciation Increase - UT	128,043
Regulatory Asset - Depreciation Increase - WY	442,191
Regulatory Asset - Environmental Costs - WA	140,390
Regulatory Asset - FAS 158 Pension Liability	13,021,776
Regulatory Asset - Goodnoe Hills Settlement - WY	21,250
Regulatory Asset - Klamath Hydroelectric Relicensing Costs - UT	3,669,527
Regulatory Asset - Lakeside Settlement - WY	27,331
Regulatory Asset - Liquidated Damages - UT	35,000
Regulatory Asset - Liquidated Damages - WY	5,708
Regulatory Asset - Postemployment Costs	413,204
Regulatory Asset - Post Merger Loss - Reacquired Debt	583,695
Regulatory Asset - Postretirement Settlement Loss	353,077
Regulatory Asset - Postretirement Settlement Loss CC - WY	22,244
Regulatory Asset - Powerdale Decommissioning - ID	23,801
Regulatory Asset - Preferred Stock Redemption Loss - UT	82,531
Regulatory Asset - Preferred Stock Redemption Loss - WA	13,318
Regulatory Asset - Preferred Stock Redemption Loss - WY	28,442
Regulatory Asset - STEP Pilot Program Balance Account - UT	5,046,761
Regulatory Asset - Utah Mine Disposition	12,965,992
Regulatory Liability - ARO/Reg Diff - Trojan - WA Portion	2,168
Regulatory Liability - Blue Sky - CA	56,886
Regulatory Liability - Blue Sky - ID	51,976
Regulatory Liability - Blue Sky - WA	161,628
Regulatory Liability - Blue Sky - WY	186,193
Regulatory Liability - Clean Fuels Program - OR	2,538,520
Regulatory Liability - Contra-Carbon Decommissioning - ID	34,621
Regulatory Liability - Contra-Carbon Decommissioning - UT	250,441
Regulatory Liability - Contra-Carbon Decommissioning - WY	623,945
Regulatory Liability - Energy Savings Assistance - CA	202,496
Regulatory Liability - FAS 158 Postretirement Liability	18,354,603
Regulatory Liability - WA Decoupling Mechanism	14,685,491
Reserve for Bad Debts	52,155
TGS Buyout	15,473
Trapper Mine Contract Obligation	305,157
Western Coal Carrier Retiree Medical Accrual	157,000
Intercompany Adjustment	4,150,876
Total	$1,250,045,963

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

Particulars (Details)	Amounts
Book Fixed Asset Gain/Loss	$ (4,186,776)
Deferred Revenue - Lease Incentives	(31,062)
Dividend Received Deduction - Deferred Compensation	(81,060)
Officer's Life Insurance	(7,841,596)
Regulatory Asset - BPA Balancing Account - OR	(1,416,010)
Regulatory Asset - BPA Balancing Account - WA	(197,289)
Regulatory Asset - Community Solar - OR	(497,724)
Regulatory Asset - REC Sales Deferral - OR	(74)
Regulatory Liability - BPA Balancing Account - ID	(471,764)
Regulatory Liability - BPA Balancing Account - WA	(469,946)
Regulatory Liability - Excess Income Tax Deferral - WY	(4,672,783)
Regulatory Liability - GHG Allowance Revenues - CA	(26,552)
Regulatory Liability - WA Low Income Program	(1,478,905)
Transmission Service Deposits	(191,377)
Trapper Mining Stock Basis	(797,264)
Equity Earnings in Subsidiaries	(23,563,311)
Total	$ (45,923,493)

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Particulars (Details)	Amounts
Accrued Bonus	$ (120,940)
Accrued Final Reclamation	(5,597,035)
Accrued Retention	(1,830,471)
Accrued Severance	(686,710)
Amortization NOPAs 99-00 RAR	(64,313)
Basis Intangible Difference	(266,104)
Bear River Settlement Agreement	(54,918)
Capitalized Depreciation	(6,684,051)
Cholla SHL NOPA (Lease Amortization)	(377,111)
Contra Receivable from Joint Owners	(665,619)
Cost of Removal	(69,673,217)
Debt AFUDC	(36,195,338)
Deferred Compensation Mark-to-Market Gain/Loss	(1,177,006)
Deferred Revenue - Citibank	(210,829)
Deferred Revenue - Other	(575,944)
Deseret Settlement Receivable	(76,495)
Dividend Deduction at 50%	(17,443)
Environmental Liability - Non-regulated	(227,637)
Equity AFUDC	(72,139,947)
FAS 158 Pension Liability	(24,625,770)
FAS 158 Postretirement Asset	(6,170,884)
FAS 158 Postretirement Liability	(1,268,785)
FAS 158 SERP Liability	(1,498,622)
Federal Tax Depreciation	(684,399,818)
Federal Tax Fixed Asset Gain/Loss	(16,502,317)
Injuries and Damages Accrual - Cash Basis	(3,786,990)
LT Incentive Plan Mark-to-Market Gain/Loss	(1,894,857)
Miscellaneous Current and Accrued Liability	(1,696,314)
N Umpqua Settlement Agreement	(649,083)
Oregon Regulatory Asset/Regulatory Liability Consolidation	(26,167)
Penalties	(1,268,517)
Pension/Retirement Accrual	(74,561)
Pre-1943 Preferred Stock Dividend - Deduction	(107,935)
Prepaid - FSA O&M - East	(252,452)
Prepaid Aircraft Maintenance	(327,259)
Prepaid Membership Fees	(126,064)
Prepaid Taxes - IPUC	(40,121)
Prepaid Taxes - Property Taxes	(1,736,838)
Property Insurance Reserve - OR	(7,594,074)
Regulatory Asset - Protocol - MSP Deferral - ID	(150,000)
Regulatory Asset - Protocol - MSP Deferral - UT	(4,400,000)
Regulatory Asset - Protocol - MSP Deferral - WY	(1,600,002)
Regulatory Asset - CA Mobile Home Park Conversion	(4,500)
Regulatory Asset - Cholla U4	(25,487,600)
Regulatory Asset - Contra Regulatory Asset - Pension Plan CTG	(1,640,983)
Regulatory Asset - Deferred Excess NPC - ID	(6,863,859)
Regulatory Asset - Deferred Excess NPC - OR	(2,980,283)
Regulatory Asset - Deferred Excess NPC - UT	(22,656,734)
Regulatory Asset - Deferred Excess NPC - WY '09 & After	(13,263,038)
Regulatory Asset - Deferred Intervenor Funding Grants - CA	(1,754)
Regulatory Asset - Deferred Intervenor Funding Grants - OR	(569,849)
Regulatory Asset - Depreciation Increase - ID	(10,028)
Regulatory Asset - Environmental Costs	(2,931,261)
Regulatory Asset - FAS 158 Postretirement Liability	(18,354,603)
Regulatory Asset - Fire Risk Mitigation - CA	(3,173,502)
Regulatory Asset - Lease Depreciation - Timing Difference	(539,026)
Regulatory Asset - Pension Settlement - WA	(1,419,060)
Regulatory Asset - Postretirement Settlement Loss CC - UT	(291,300)
Regulatory Asset - Solar Feed-In Tariff Deferral - OR	(508,246)
Regulatory Asset - Solar Incentive Program - UT	(5,046,761)
Regulatory Asset - Transportation Electrification Program - CA	(61,654)
Regulatory Asset - Transportation Electrification Program - OR	(768,596)
Regulatory Asset - Transportation Electrification Program - WA	(137,015)
Regulatory Asset - UT Subscriber Solar Program	(61,577)
Regulatory Liability - 50% Bonus Tax Depreciation - WY	(810,660)
Regulatory Liability - Blue Sky - OR	(122,949)
Regulatory Liability - Blue Sky - UT	(1,327,673)
Regulatory Liability - Deferred Excess NPC - WA	(14,326,872)
Regulatory Liability - OR Energy Conservation Charge	(603,039)
Regulatory Liability - Solar Feed-in Tariff Deferral - CA	(2,458,183)

Repairs Deduction	(155,652,559)
Rogue River - Habitat Enhancement Liability	(73,640)
Right of Way Asset (Operating Leases)	(12,161,674)
Sales & Use Tax Audit Exposure	(250,977)
Sec. 481a Adjustment	(11,174,667)
Tax Depletion - SRC	(30,909)
Tax Percentage Depletion - Blundell Steam Field	(9,453)
Trojan Decommissioning	(60,836)
Wasatch Workers Compensation Reserve	(179,531)
Total	$(1,262,853,409)

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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.
Aeronavis LLC
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
BH2H Holdings, LLC
BHE AC Holding, LLC
BHE America Transco, LLC
BHE Canada LLC
BHE Community Solar, LLC
BHE Compression Services, LLC
BHE CS Holdings, 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
BHES CSG Holdings, LLC
BHES Pearl Solar Holdings, LLC
BHH Affiliates, LLC
BHH Iowa Affiliates, LLC
BHH KC Real Estate, LLC
Bishop Hill Energy II, LLC
Bishop Hill II Holdings, LLC
BRER Affiliates, 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 Yuma Corporation
California Utility Holdco, LLC
Capitol Title Company
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, Inc.
CE Electric (NY), Inc.
CE Generation LLC
CE Geothermal, Inc.
CE International Investments, Inc.
CE Leathers Company
CE Salton Sea Inc.
CE Turbo LLC
Champion Realty, Inc.
Chancellor Title Services, Inc.
Columbia Title of Florida, Inc.
Commonsite, Inc.
Conejo Energy Company
Cordova Energy Company, LLC
CTRE, L.L.C.
Dakota Dunes Development Company
DCCO, Inc.
Del Ranch Company
Denver Rental, LLC
Desert Valley Company
Ebby Halliday Properties, Inc.
Ebby Halliday Real Estate, Inc.
Edina Financial Services, Inc.
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.
Fishlake Power LLC
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
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 Nevada, LLC
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 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.
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 Referral, Inc.

Nevada Power Company d/b/a NV Energy
Niguel Energy Company
NNGC Acquisition LLC
Northeast Referral Group, LLC
Northern Natural Gas Company
NRS Referral Services, LLC
NV Energy, Inc.
NVE Holdings, LLC
NVE Insurance Co, Inc.
NW Referral Services, LLC
PCG Agencies, Inc.
PCRE, L.L.C.
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
Prime Alliance Real Estate Services, LLC
Priority Title Corporation
Professional Referral Organization, Inc.
Prosperity First Title, LLC
Prosperity Home Mortgage, LLC
Pru-One, Inc.
Real Estate Knowledge Services, L.L.C.
Real Estate Links, LLC
Real Estate Referral Network, Inc.
Real Living Real Estate, LLC
Reece & Nichols Alliance, Inc.
Reece & Nichols Realtors, Inc.
Reece Commercial, Inc.
Referral Associates of Georgia, LLC
Referral 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 Power Company
Salton Sea Power Generation Company
Salton Sea Power LLC
San Felipe Energy Company
Santa Rita Wind Energy LLC
Saranac Energy Company, Inc.
SCS Realty Investment Group, LLC
Sequoia Aviation Corporation
Sierra Gas Holding Company
Sierra Pacific Power Company d/b/a NV Energy
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
TX Referral Alliance, Inc.
Volantes 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
Watermark Realty Referral, Inc.
Watermark Realty, Inc.
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.
A.E. Company, Inc.
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.
Aero-Hose Corporation
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.
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.
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
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 Supply, 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 Transport, Inc.
Coil Master Corporation
Columbia Insurance Company
Combined Claims Services, Inc.
Commercial General Indemnity, 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.
Crown Holdco One, Inc.
Crown Holdco Two, Inc.
Crown Parent, 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.
DCI Marketing Inc.
Denver Brick Company
Designed Metal Connections, Inc.
Dickson Testing Co., Inc.
Display Technologies LLC
DL Trading Holdings I, Inc.
DQ Funding Corporation
DQF, Inc.
DQGC, Inc.
DragonFly Aeronautics LLC
DTTF, Inc.
Duracell Industrial Operations, Inc.

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
Hohmann & Barnard, Inc.
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Howell Penncraft, Inc.
Huntington Alloys Corporation
IdeaLife Insurance Company
Illinois Insurance Company
Ingersoll Cutting Tool Company
Innovative Building Products, Inc.
Innovative Coatings Technology Corporation
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 Fiber Services Inc.
J.L. Mining Company
Johns Manville China, Ltd.
Johns Manville Corporation
Johns Manville, Inc.
Jordan's Furniture, Inc.
Joyce Crane, Inc.
Joyce Steel Erection, Ltd.
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
LSPI Holdings Inc.
Lubrizol Advanced Materials Holding Corporation
Lubrizol Advanced Materials, Inc.
Lubrizol Global Management, Inc.
Lubrizol Inter-Americas Corporation
Lubrizol International Management Corporation
Lubrizol International, 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 Link 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 Liability Services, Inc.
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 Inc.
MiTek Industries, Inc.
MLMIC Insurance Company
MLMIC Services, Inc.
Morgantown-National Supply, Inc.
Mount Vernon Fire Insurance Company
Mount Vernon Specialty Insurance Company
Mouser Electronics, Inc.
Mouser JV 1, Inc.
Mouser JV 2
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.
NewCo D&W LLC
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.
Precision Brand Products, Inc.
Precision Castparts Corp.
Precision Founders Inc.
Precision Steel Warehouse, Inc.
Press Forge Company
Primus International Holding Company
Primus International 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
QS Security Services 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.
Sager Electrical Supply Co. Inc.

Santa Fe Pacific Insurance Company
Santa Fe Pacific Pipeline Holdings, Inc.
Santa Fe Pacific Pipelines, Inc.
Santa Fe Pacific Railroad Company
Schulz Investment Corporation
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, 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.
Technical Power Systems, Inc.
Texas Honing Inc.
Texas Insurance Company
The Ben Bridge Corporation
The Buffalo News, Inc.
The BVD Licensing Corporation
The Duracell Company
The Fechheimer Brothers Co.
The Indecor Group, Inc.
The Lubrizol Corporation
The Medical Protective Company
The Pampered Chef, Ltd.
The Scott Fetzer Company
The Zia Company
THI Acquisition Inc.
TIMET ASIA Inc.
TIMET Real Estate Corporation
Titanium Metals Corporation
TM City Leasing Inc.
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 Railcar Repair Inc.
Transco Railway Products Inc.
Transco, Inc.
Transportation Technology Services, Inc.
TRH Holding Corp.
Triangle Suspension Systems, Inc.
Tricycle, Inc.
TS City Leasing Inc.
TSE Brakes, Inc.
TTI JV 1
TTI JV 2
TTI, Inc.
Tucker Safety Products, Inc.
TXFM, Inc.
U.S. Investment Corporation
U.S. Underwriters Insurance Co.
UCFS Europe Company
UCFS International Holding Company
Unified Supply Chain, Inc.
Uni-Form Components Co.
Union Sales, LLC
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.
Wellfleet Insurance Company
Wellfleet New York Insurance Company
Western Builders Supply, Inc.
Western Fruit Express Company
Western/Scott Fetzer Company
WestGUARD Insurance Company
Whittaker, Clark & Daniels, Inc.
World Book Encyclopedia, Inc.
World Book, Inc.
World Book/Scott Fetzer Company
World Investments, Inc.
Worldwide Containers, Inc.
WPLG, Inc.
Wyman Gordon Company
Wyman Gordon Forgings Cleveland Inc.
Wyman Gordon Forgings Inc.
Wyman Gordon Investment Castings 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 2019/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	4,019,911		149,204,059	127,940,482	
3	FICA	543,289		37,718,198	37,713,512	
4	Unemployment	6,435		229,759	229,261	
5	Foreign Withholding Taxes	1,522,888		-1,522,888		
6	Subtotal	6,092,523		185,629,128	165,883,255	
7						
8	State:					
9						
10	Arizona:					
11	Property	1,436,370		2,694,681	2,783,711	
12	Income	1,756		75,715	217,989	
13	Subtotal	1,438,126		2,770,396	3,001,700	
14						
15	California:					
16	Property			2,362,204	2,362,204	
17	Unemployment	1,532		20,536	21,718	
18	Franchise-Income	621,704		1,398,520	1,799,700	
19	Use	10,045		350,979	339,047	
20	Local Franchise	1,373,864		1,207,395	1,216,077	
21	Subtotal	2,007,145		5,339,634	5,738,746	
22						
23	Colorado:					
24	Property	2,850,000		2,980,214	3,000,214	
25	Income			1,769		
26	Subtotal	2,850,000		2,981,983	3,000,214	
27						
28	Idaho:					
29	Property	3,698,211		6,226,628	6,302,994	
30	Income	69,593		1,665,153	1,521,033	
31	KWh	17,170		58,058	57,888	
32	Unemployment	1,557		27,777	28,492	
33	Use	36,473		490,384	507,357	
34	Subtotal	3,823,004		8,468,000	8,417,764	
35						
36	Missouri:					
37	Unemployment			285	285	
38	Subtotal			285	285	
39						
40						
41	TOTAL	48,581,847	13,873,220	438,272,040	415,419,512	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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
25,283,488		151,665,847			-2,461,788	2
547,975					37,718,198	3
6,933					229,759	4
					-1,522,888	5
25,838,396		151,665,847			33,963,281	6
						7
						8
						9
						10
1,347,340		2,694,681				11
-140,518		70,393			5,322	12
1,206,822		2,765,074			5,322	13
						14
						15
		2,087,104			275,100	16
350					20,536	17
220,524		1,430,680			-32,160	18
21,977					350,979	19
1,365,182		1,207,395				20
1,608,033		4,725,179			614,455	21
						22
						23
2,830,000		2,978,742			1,472	24
1,769		1,790			-21	25
2,831,769		2,980,532			1,451	26
						27
						28
3,621,845		6,121,555			105,073	29
213,713		1,703,519			-38,366	30
17,340		58,058				31
842					27,777	32
19,500					490,384	33
3,873,240		7,883,132			584,868	34
						35
						36
					285	37
					285	38
						39
						40
71,717,476	14,156,321	385,723,458			52,548,582	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 2019/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	Montana:					
2	Property	2,833,586		5,149,080	5,410,425	
3	Corporate License-Income	9,454		209,085	182,540	
4	Unemployment			145	145	
5	Energy License	60,000		228,670	228,670	
6	Wholesale Energy	42,000		162,925	162,925	
7	Subtotal	2,945,040		5,749,905	5,984,705	
8						
9	Nevada:					
10	Commerce Tax	18,000		34,881	34,881	
11	Subtotal	18,000		34,881	34,881	
12						
13	New Mexico:					
14	Property			21,147	21,147	
15	Income	6,916		123,702	178,437	
16	Subtotal	6,916		144,849	199,584	
17						
18	Oregon:					
19	Property	228,143	13,011,465	26,347,870	26,802,684	
20	Unemployment	58,423		1,336,269	1,337,256	
21	Excise-Income	-482,078		15,573,591	13,565,592	
22	City of Portland-Income	12,745		65,757	85,985	
23	Department of Energy		861,755	1,611,450	1,499,390	
24	Tri-Met	392,119		1,099,504	1,069,547	
25	Lane County			567	567	
26	Franchise	4,552,678		30,247,957	29,871,656	
27	Subtotal	4,762,030	13,873,220	76,282,965	74,232,677	
28						
29	Texas:					
30	Unemployment			32	32	
31	Subtotal			32	32	
32						
33	South Carolina:					
34	Public Utility				25	
35	Subtotal				25	
36						
37						
38						
39						
40						
41	TOTAL	48,581,847	13,873,220	438,272,040	415,419,512	

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
2,572,241		5,149,080				2
35,999		212,082			-2,997	3
					145	4
60,000		228,670				5
42,000		162,925				6
2,710,240		5,752,757			-2,852	7
						8
						9
18,000		34,881				10
18,000		34,881				11
						12
						13
		21,147				14
-47,819		125,173			-1,471	15
-47,819		146,320			-1,471	16
						17
						18
168,490	13,406,626	24,808,302			1,539,568	19
57,436					1,336,269	20
1,525,921		15,809,485			-235,894	21
-7,483		66,979			-1,222	22
	749,695	1,611,450				23
422,076					1,099,504	24
					567	25
4,928,979		30,247,957				26
7,095,419	14,156,321	72,544,173			3,738,792	27
						28
						29
					32	30
					32	31
						32
						33
-25						34
-25						35
						36
						37
						38
						39
						40
71,717,476	14,156,321	385,723,458			52,548,582	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 2019/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Utah:					
2	Property	742,013		79,286,151	79,172,999	
3	Income	634,464		15,249,767	14,653,584	
4	Unemployment	1,738		70,665	70,635	
5	Use	318,777		5,005,170	4,821,575	
6	Subtotal	1,696,992		99,611,753	98,718,793	
7						
8	Washington:					
9	Property	12,000,000		9,275,320	10,675,320	
10	Unemployment	720		29,438	20,228	
11	Family & Medical Leave			6,032	3,973	
12	Business & Occupation	3,300		23,114	22,814	
13	Public Utility	-483,627		12,517,338	12,224,320	
14	Natural Gas Use Tax	139,156		2,955,292	2,702,405	
15	Use	102,048		2,179,741	866,643	
16	Forest Excise Tax			39,757	39,757	
17	Franchise			3,121	3,121	
18	Subtotal	11,761,597		27,029,153	26,558,581	
19						
20	Wyoming:					
21	Property	8,554,150		18,375,708	17,748,296	
22	Wind Generation Tax	2,031,616		2,050,814	2,045,353	
23	Unemployment	2,665		84,146	84,887	
24	Franchise	287,200		1,916,550	1,895,550	
25	Use	225,526		1,227,046	1,371,551	
26	Annual Report			76,984	76,984	
27	Subtotal	11,101,157		23,731,248	23,222,621	
28						
29	Miscellaneous:					
30	Goshute Possessory			29,054	29,054	
31	Sho-Ban Possessory			271,335	271,335	
32	Navajo Possessory	7,317		14,993	14,814	
33	Ute Possessory			40,695	40,695	
34	Crow Possessory	72,000		72,000		
35	Umatilla Possessory			69,751	69,751	
36	Subtotal	79,317		497,828	425,649	
37						
38						
39						
40						
41	TOTAL	48,581,847	13,873,220	438,272,040	415,419,512	

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
855,165		79,123,372			162,779	2
1,230,647		15,500,484			-250,717	3
1,768					70,665	4
502,372		208,382			4,796,788	5
2,589,952		94,832,238			4,779,515	6
						7
						8
10,600,000		8,502,236			773,084	9
9,930					29,438	10
2,059					6,032	11
3,600		23,114				12
-190,609		12,517,338				13
392,043					2,955,292	14
1,415,146					2,179,741	15
					39,757	16
		3,121				17
12,232,169		21,045,809			5,983,344	18
						19
						20
9,181,562		16,805,340			1,570,368	21
2,037,077		2,050,814				22
1,924					84,146	23
308,200		1,916,550				24
81,021					1,227,046	25
		76,984				26
11,609,784		20,849,688			2,881,560	27
						28
						29
		29,054				30
		271,335				31
7,496		14,993				32
		40,695				33
144,000		72,000				34
		69,751				35
151,496		497,828				36
						37
						38
						39
						40
71,717,476	14,156,321	385,723,458			52,548,582	41

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

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

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

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

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

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

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

$(1,271,911)	Account 426.3, Penalties
(250,977)	Account 431, Other interest expense
$(1,522,888)	

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

$ 139,809	Account 408.2, Taxes other than income taxes, other income and deductions
135,291	Account 107, Construction work in progress
$ 275,100	

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: 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.: 25 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.: 29 Column: l

$ 1,080	Account 408.2, Taxes other than income taxes, other income and deductions
103,993	Account 107, Construction work in progress
$ 105,073	

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

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

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

Charged to same account as related goods.

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

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

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: 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: l

$ 26,613	Account 408.2, Taxes other than income taxes, other income and deductions
170,849	Account 589, Rents
1,342,106	Account 107, Construction work in progress
$ 1,539,568	

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

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

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

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: 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: 262.2 Line No.: 2 Column: l

$ 69,378	Account 408.2, Taxes other than income taxes, other income and deductions
93,401	Account 107, Construction work in progress
$ 162,779	

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

Charged to same account as related goods.

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

$ 36,882	Account 408.2, Taxes other than income taxes, other income and deductions
736,202	Account 107, Construction work in progress
$ 773,084	

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

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

Schedule Page: 262.2 Line No.: 11 Column: l

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

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

Account 151, Fuel stock

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

Charged to same account as related goods.

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

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

Schedule Page: 262.2 Line No.: 21 Column: l

$ 3,249	Account 408.2, Taxes other than income taxes, other income and deductions
13,753	Account 589, Rents
1,553,366	Account 107, Construction work in progress
$ 1,570,368	

Schedule Page: 262.2 Line No.: 23 Column: l

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

Schedule Page: 262.2 Line No.: 25 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 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	8,880,380			411.4,420	2,759,658	
6	30%	222,376			420	11,696	
7	Idaho	82,772			411.4,420	13,641	
8	TOTAL	9,185,528				2,784,995	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Idaho	4,128,249	190	1,023,832	420	306,160	-42,947
12	Total Nonutility	4,128,249		1,023,832		306,160	-42,947
13							
14							
15							
16							
17							
18							
19							
20							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
6,120,722	38.82 and 30		5
210,680	24		6
69,131	38.82 and 30		7
6,400,533			8
			9
			10
4,802,974	30		11
4,802,974			12
			13
			14
			15
			16
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			21
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			45
			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%	$ 8,823,458	-	$ -	411.4(1)	$2,730,882	$ -	$ 6,092,576	38.82
10%	56,922	-	-	420(2)	28,776	-	28,146	30
	$ 8,880,380		$ -		$2,759,658	$ -	$ 6,120,722	

(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	$ 41,660	-	$ -	411.4(1)	$ 7,842	$ -	$ 33,818	38.82
Idaho	41,112	-	-	420(2)	5,799	-	35,313	30
	$ 82,772		$ -		$ 13,641	$ -	$ 69,131	

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

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

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

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	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Working Capital Deposits	5,574,362	131	227,000	26,729	5,374,091
2	Reclamation Costs - Trapper Mine	6,498,181			224,859	6,723,040
3	Western Coal Carriers Benefits					
4	Obligation	10,479,000	131	725,579	882,579	10,636,000
5	Deferred Compensation Plans	8,609,477	131	960,622	2,410,219	10,059,074
6	Long-Term Incentive Plan	20,751,400	131	5,523,430	6,745,025	21,972,995
7	Regulated Environmental					
8	Liabilities	55,506,640	131,182.3	12,139,162	12,976,108	56,343,586
9	Non-Regulated Environmental					
10	Liabilities	1,947,013	131,426.5	316,261	88,624	1,719,376
11	Unearned Joint Use					
12	Pole Contact Revenue	2,876,703	454	6,305,398	6,461,038	3,032,343
13	Misc. Security Deposits	119,307	415	38,981	29,225	109,551
14	Lease Incentives	155,310	931	31,062		124,248
15	Cowlitz/Lewis River O&M (1)	126,656	539	307,828	310,582	129,410
16	Employee Housing Security Deposits	18,900	131	1,600	4,700	22,000
17	Cogeneration Bonds-Sunnyside	413,417				413,417
18	Transmission Security Deposits	7,735,000	131	1,437,229	4,190,279	10,488,050
19	Transmission Service Deposits	2,335,548	131,235	724,660	533,283	2,144,171
20	MCI F.O.G. Wire Lease (1)	558,002	454	3,351,249	3,351,896	558,649
21	Unamortized Contract Values	67,454,522	242	13,958,150		53,496,372
22	Accrued Right-of-Way Obligations	2,420,292			409,029	2,829,321
23	Facility Use Fee	886,164	451,456	148,646	106,035	843,553
24	Energy Supply Management					
25	Deferral (1)	579,167	456	533,333		45,834
26	Deer Creek Accrued Royalties	7,182,957			447,854	7,630,811
27	Deferred Revenue - Other	291,664	456,921	221,387		70,277
28	Coal Contract Costs - Naughton				6,664,437	6,664,437
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	202,519,682		46,951,577	45,862,501	201,430,606

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 four years.

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

The weighted average remaining life is 13 years.

Schedule Page: 269 Line No.: 27 Column: a

The weighted average remaining life is one year for amounts being amortized to Account 921, Office supplies and 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 2019/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	180,339,430	1,761,741	7,271,333
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	180,339,430	1,761,741	7,271,333
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)	180,339,430	1,761,741	7,271,333
18	Classification of TOTAL			
19	Federal Income Tax	147,039,137	459,880	4,952,107
20	State Income Tax	33,300,293	1,301,861	2,319,226
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 2019/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
						174,829,838	4
							5
							6
							7
						174,829,838	8
							9
							10
							11
							12
							13
							14
							15
							16
						174,829,838	17
							18
						142,546,910	19
						32,282,928	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	2,910,580,066	332,718,514	493,943,276
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,910,580,066	332,718,514	493,943,276
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	2,910,580,066	332,718,514	493,943,276
10	Classification of TOTAL			
11	Federal Income Tax	2,397,447,703	214,925,144	372,073,979
12	State Income Tax	513,132,363	117,793,370	121,869,297
13	Local Income Tax			

NOTES

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	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	10,856,821	182.3,254	151,331,396	2,889,829,879	2
							3
							4
			10,856,821		151,331,396	2,889,829,879	5
							6
							7
							8
			10,856,821		151,331,396	2,889,829,879	9
							10
			9,036,261		146,504,450	2,377,767,057	11
			1,820,560		4,826,946	512,062,822	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 2019/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets	273,373,737	51,134,439	27,003,311
4	Other	12,415,773	15,037,286	12,355,184
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	285,789,510	66,171,725	39,358,495
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)	285,789,510	66,171,725	39,358,495
20	Classification of TOTAL			
21	Federal Income Tax	233,251,811	53,796,638	31,934,563
22	State Income Tax	52,537,699	12,375,087	7,423,932
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
23,056,830	35,907,554		15,939,885		7,425,764	276,140,020	3
8,224,329	6,850,299	190,283	795,015	190,283	5,356,639	21,033,529	4
							5
							6
							7
							8
31,281,159	42,757,853		16,734,900		12,782,403	297,173,549	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
31,281,159	42,757,853		16,734,900		12,782,403	297,173,549	19
							20
25,438,621	34,801,434		13,845,586		10,622,931	242,528,418	21
5,842,538	7,956,419		2,889,314		2,159,472	54,645,131	22
							23

NOTES (Continued)

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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 (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	DSM Balancing Account - CA	2,922,817	440,442,444	3,068,342	1,612,790	1,467,265
2	DSM Balancing Account - ID	1,541,064	440,442,444	4,988,861	4,514,577	1,066,780
3	DSM Balancing Account - UT	13,057,310		64,279,369	65,528,784	14,306,725
4	DSM Balancing Account - WA	1,757,029	440,442,444	9,421,797	11,379,220	3,714,452
5	DSM Balancing Account - WY	1,594,641	440,442,444	1,594,641		
6	Oregon Energy Conservation Charge	4,375,327	440,442,444	33,594,629	32,991,590	3,772,288
7	Deferred Excess Net Power Costs - WA	23,066,215	555	15,803,826	1,476,954	8,739,343
8	Deferred Excess RECs in Rates - UT				648,863	648,863
9	Deferred Excess RECs in Rates - WY				61,621	61,621
10	Decoupling Mechanism - WA	3,322,101	440,442	3,149,670	17,835,161	18,007,592
11	Income Tax Reg. Liability - Flow Through - WA	738,932			449,460	1,188,392
12	Investment Tax Credit Regulatory Liability	2,359,058	190	728,701	214	1,630,571
13	Deferred Income Tax Electric	1,800,050,610	190,282,411.1	315,159,490	165,363,718	1,650,254,838
14	Excess Income Tax Deferral	68,343,778	440,442,444	21,464,040	24,059,889	70,939,627
15	Tax on Bonus Depreciation - WY (1)	2,066,824	440,442,444	1,528,422	717,762	1,256,164
16	Other Postretirement				18,354,603	18,354,603
17	Depreciation Study Deferral - ID (1)	86,905	403	1,914,765	1,904,737	76,877
18	Asset Retirement Obligations Reg. Difference	3,421,452	230	3,350,356		71,096
19	Greenhouse Gas Allowance Compliance - CA	3,375,158	456,555,131	4,039,385	4,012,833	3,348,606
20	Solar Feed-In Tariff Deferral - CA	623,230				623,230
21	Solar Incentive Program - UT	14,258,175		8,869,138	1,364,194	6,753,231
22	STEP Pilot Program - UT	9,734,546		11,318,294	16,365,055	14,781,307
23	Renewable Portfolio Standards Compliance - OR				22,637	22,637
24	Independent Evaluator Costs - UT	107,882				107,882
25	Utah Home Energy Lifeline	1,510,555	142	198,273	244,966	1,557,248
26	Washington Low Income Program	504,027	142	504,027		
27	California Energy Savings Assistance Program	435,264	142	616,464	818,960	637,760
28	FERC Rate True-up - OR (3)	30,455,865	456	6,952,834	12,431,790	35,934,821
29	BPA Balancing Account - ID	3,363,350	440,442	471,764		2,891,586
30	BPA Balancing Account - WA	469,946	440,442	469,946		
31	Blue Sky - CA	214,432			56,886	271,318
32	Blue Sky - OR	2,563,475	440,442	310,849	187,900	2,440,526
33	Blue Sky - ID	241,534			51,976	293,510
34	Blue Sky - UT	9,991,032	107	2,001,273	673,602	8,663,361
35	Blue Sky - WA	380,902			161,628	542,530
36	Blue Sky - WY	466,343			186,193	652,536
37	Depreciation Deferral - OR	5,223,348			1,304,531	6,527,879
38	Deferred Steam Accel. Depreciation - WA	27,034,388	182.3	6,648	12,611,581	39,639,321
39	Merwin Fish Collector Project - WA	3,432				3,432
40	Direct Access 5-Year Opt Out - OR (10)	3,633,859	442	1,684,530	3,602,263	5,551,592
41	TOTAL	2,044,239,906		517,565,220	403,548,690	1,930,223,376

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	232,908	71,231	9,577	395,946
2	Oregon Clean Fuels Program	487,500	232,908	3,655	2,542,175	3,026,020
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40						
41	TOTAL	2,044,239,906		517,565,220	403,548,690	1,930,223,376

Schedule Page: 278 Line No.: 3 Column: c

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 908, Customer Assistance Expenses

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.: 14 Column: a

Weighted average remaining life is approximately one year for excess income tax defferals in rates being amortized.

Schedule Page: 278 Line No.: 19 Column: a

Includes California Solar on Multifamily Affordable Housing

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.: 22 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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,815,760,353	1,774,237,100
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,547,127,608	1,541,492,719
5	Large (or Ind.) (See Instr. 4)	1,316,469,104	1,322,455,444
6	(444) Public Street and Highway Lighting	18,198,044	18,155,451
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,697,555,109	4,656,340,714
11	(447) Sales for Resale	192,271,657	254,214,730
12	TOTAL Sales of Electricity	4,889,826,766	4,910,555,444
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,889,826,766	4,910,555,444
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,415,631	9,811,199
17	(451) Miscellaneous Service Revenues	8,845,804	6,172,987
18	(453) Sales of Water and Water Power	53,658	54,615
19	(454) Rent from Electric Property	17,459,728	17,246,955
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	28,198,210	29,900,870
22	(456.1) Revenues from Transmission of Electricity of Others	111,912,996	116,616,886
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	175,886,027	179,803,512
27	TOTAL Electric Operating Revenues	5,065,712,793	5,090,358,956

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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
16,668,416	16,227,117	1,681,634	1,651,326	2
				3
18,150,545	18,078,160	214,182	211,800	4
20,395,896	20,679,901	33,151	33,186	5
127,750	130,278	3,565	3,501	6
				7
				8
				9
55,342,607	55,115,456	1,932,532	1,899,813	10
5,479,628	8,309,472			11
60,822,235	63,424,928	1,932,532	1,899,813	12
				13
60,822,235	63,424,928	1,932,532	1,899,813	14

Line 12, column (b) includes $ 244,728,000 of unbilled revenues.

Line 12, column (d) includes 2,903,366 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 FERC 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 December 31, 2018 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:

	2019	2018
Account service charges - application fees, disconnects, reconnects and returned check charges	$ 7,556,998	$ 5,274,993
Customer contract flat rate billings and facility buyout charges	1,272,737	873,886

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:

	2019	2018
Amortization of California greenhouse gas allowance revenue	$ 12,254,503	$ 9,591,652
Wind-based ancillary services	9,193,455	11,169,083
Flyash/by-product sales	4,075,964	4,258,230
Renewable energy credit sales, including amortization and deferrals	2,878,143	3,300,207
Timber sales	649,985	506,102
Steam sales	557,219	689,865
Revenues for assigned purchased power agreement	533,333	350,000
Maintenance charges for work on transmission facilities	471,749	432,874
Revenues from generation interconnection and transmission service request studies	400,637	1,659,764
Phase shifting equipment fee from Western Electricity Coordinating Council	(a)	1,380,032
Revenues from other requested customer studies	(a)	266,676
Net loss on sales of materials and supplies inventory	(331,617)	(a)
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	(3,135,370)	(4,129,687)

(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		3,087			
5	06NETMT135 - CA RES NET MTR	2,333	250,518	434	5,376	0.1074
6	06OALT015R - OUTD AR LGT SR	264	75,948	280	943	0.2877
7	06RESD000D - RES SRVC	165,982	20,920,308	17,334	9,576	0.1260
8	06RESD00DN - DEL NORTE CTY	75,330	9,654,880	6,904	10,911	0.1282
9	06RESDDL06 - CA LOW INCOME	116,934	14,846,440	11,348	10,304	0.1270
10	06RGNSV025 - CA SMALL GEN	1,396	299,859	478	2,921	0.2148
11	06RNM25135 - CA NET MTR, GEN		93	1		
12	06RESD0DM9 - MULTI FAMILY	167	17,645	7	23,857	0.1057
13	06RESD0DS8 - MULT FAM SBMET	1,538	132,440	18	85,444	0.0861
14	REVENUE - ACCT ADJ		-184,385			
15	INCOME TAX DEFERRAL ADJ		-1,931,372			
16	DSM REVENUE - RESIDENTIAL		1,540,309			
17	BLUE SKY REV - RESIDENTIAL		25,290			
18	OTHER CUST RETAIL REV		28,114			
19	UNBILLED REVENUE	-437	521,000			-1.1922
20	UNBILLED REV - UNCOLLECTIBLE		-3,000			
21						
22	IDAHO					
23	07LNX00010 - MNTHLY 80%GTY		1,173			
24	07LNX00035 - ADV 80%MO GTY		2,650			
25	07NETMT135 - ID RES NET MTR	7,230	619,805	889	8,133	0.0857
26	07OALCO007 - CUST OWN LIGHT	10	3,805	1	10,000	0.3805
27	07OALT07AR - SECURITY AR LG	94	38,536	118	797	0.4100
28	07RESD0001 - RES SRVC	518,009	58,299,042	54,003	9,592	0.1125
29	07RESD0036 - RES SRVC-OPTIO	193,631	18,531,010	11,225	17,250	0.0957
30	07RGNSV06A - LRG GEN SVC-RES	304	25,546	3	101,333	0.0840
31	07RGNSV23A - SM GEN SVC-RES	9,374	1,039,560	1,098	8,537	0.1109
32	07RNM23135 - NET MTR SMALL	253	21,161	6	42,167	0.0836
33	REVENUE - ACCT ADJ		-275,674			
34	INCOME TAX DEFERRAL ADJ		-49,462			
35	DSM REVENUE - RESIDENTIAL		1,995,565			
36	BLUE SKY REV - RESIDENTIAL		9,092			
37	UNBILLED REVENUE	6,252	595,000			0.0952
38	UNBILLED REV - UNCOLLECTIBLE		9,000			
39						
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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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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	OREGON					
2	01CHCK000R - RES CHECK MTR			1		
3	01COST0004 - 01RESD0004	5,060,497	310,044,448			0.0613
4	01COSTR023 - RES GEN SRV CST	95,894	5,933,876			0.0619
5	01COSTR028 - OR RES GEN SVC	48,432	2,983,843			0.0616
6	01FXRENEWR - FIXED		-4			
7	01HABIT004 - 01RESD0004	54,244	3,261,741			0.0601
8	01HABTR023 - RES GEN SVC HAB	203	12,863			0.0634
9	01LNX00102 - LINE EXT 80% GTY		9,729			
10	01LNX00109 - REF/NREF ADV +		3,889			
11	01LNX00300 - LINE EXT 80% GTY		142			
12	01NETMT135 - NET METERING		2,394,056	5,798		
13	01NMTOU135 - TOU NET		-23,782	32		
14	01OALTB15R - OR OUTD AR LGT	2,037	326,228	2,373	858	0.1602
15	01PTOU0004 - 01RESD0004	13,196	829,919			0.0629
16	01PTOU0005 - 01RESEV05T TOU	4	227			0.0568
17	01RENEW004 - 01RESD0004	408,656	24,225,804			0.0593
18	01RENWR023 - RENEW USAGE	780	47,084			0.0604
19	01RESD0004 - RES SRVC		277,400,261	504,087		
20	01RESD004T - RES TIME OPT		667,762	986		
21	01RESEV05T- RES ELECT		290	1		
22	01RGNSB023 - SM GEN SVC-RES		6,995,462	17,041		
23	01RGNSB028 - GEN SVC > 30 KW -		1,218,657	213		
24	01RNETM023 - NET MTR RES GEN		52,721	131		
25	01RNETM028 - NET MTR RES GEN		51,682	4		
26	01UPPL000R - BASE SCH FALL			2		
27	01VIR04136 - VOLUME INCENTIVE		360,131	471		
28	REVENUE - ACCT ADJ		-3,042,695			
29	OR GAIN ON SALE OF ASSET		17,150			
30	INCOME TAX DEFERRAL ADJ		215,593			
31	DSM REVENUE - RESIDENTIAL		19,782,965			
32	BLUE SKY REV - RESIDENTIAL		616,900			
33	SOLAR FEED-IN REVENUE		1,839,427			
34	COMMUNITY SOLAR REVENUE		50,481			
35	UNBILLED REVENUE	38,169	5,165,000			0.1353
36	UNBILLED REV - UNCOLLECTIBLE		-40,000			
37						
38						
39						
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	UTAH					
2	08CFR00001 - MTH FACILITY S		713			
3	08CGENR136 - UT RES TRANS	209	23,241	26	8,038	0.1112
4	08CGR01136 - UT RES TRANS	36,356	3,917,392	5,027	7,232	0.1078
5	08CGR02136 - UT RES TOU TRANS	21	2,232	4	5,250	0.1063
6	08CGR03136 - UT LOW INC RES	257	27,466	34	7,559	0.1069
7	08CGR23136 - RES SMALL GEN	117	9,795	3	39,000	0.0837
8	08CHCK000R - UT RES CHECK M			1		
9	08COOLKPRR - COOL KEEPER		1,573	99,763		
10	08LNX00001 - MTHLY 80% GUAR		2,895			
11	08LNX00005 - MTHLY MIN GUAR		396			
12	08LNX00013 - 80% MNTHLY MIN		27,115			
13	08LNX00108 - ANN COST MTHLY		1,656			
14	08MHTP0006 - MOBILE HOME &	11,618	857,261	8	1,452,250	0.0738
15	08MHTP0023 - MOBILE HOME &	114	8,826	1	114,000	0.0774
16	08NETMT135 - NET MTR	117,500	13,815,643	29,676	3,959	0.1176
17	08NMT03135 - LOW INC RES NET	1,102	119,182	193	5,710	0.1082
18	08OALT007R - SECURITY AR LG	2,253	625,708	2,277	989	0.2777
19	08PTLD000R - POST TOP LIGHT	1	105	2	500	0.1050
20	08RCG23136 - RES NET MTR,	28	3,374	5	5,600	0.1205
21	08RESD0001 - RES SRVC	6,510,293	695,965,278	767,739	8,480	0.1069
22	08RESD0002 - RES SRVC-OPTIO	3,071	323,128	385	7,977	0.1052
23	08RESD0003 - LIFELINE PRGRM	152,216	16,009,140	21,009	7,245	0.1052
24	08RESD002E - RES ELECT	4,043	342,218	285	14,186	0.0846
25	08RGNSV006 - GEN SRVC-RES	124,273	9,226,908	289	430,010	0.0742
26	08RGNSV008 - UT RES GEN SVC	451	32,041	1	451,000	0.0710
27	08RGNSV023 - GEN SRVC-RES	101,822	10,867,749	13,824	7,366	0.1067
28	08RGNSV06A - UT SMALL GEN	8,683	735,569	28	310,107	0.0847
29	08RGNSV06B - UT SMALL GEN	25	3,499	1	25,000	0.1400
30	08RNM06135 - UT NET MTR, GEN	3,782	323,190	13	290,923	0.0855
31	08RNM23135 - UT NET MTR, GEN	1,240	161,144	435	2,851	0.1300
32	08RNM6A135 - RES GEN SVC NET	6	5,343	2	3,000	0.8905
33	08RTCVLNGA - TCV LNX GAR		446			
34	08SSLR0001 - RES SUBSCRB	34,093	3,208,694			0.0941
35	08SSLR0003 - RES LOW INC	263	25,160	23	11,435	0.0957
36	08SSLRRG23 - RES SMALL GEN	69	7,787	17	4,059	0.1129
37	08UPPL000R - BASE SCH FALL			4		
38	REVENUE - ACCT ADJ		-1,227,136			
39	REVENUE ADJ - DEF NPC		2,405,361			
40	DSM REVENUE - RESIDENTIAL		3,637,605			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	BLUE SKY REV - RESIDENTIAL		2,162,997			
2	SOLAR FEED-IN REVENUE		1,838,486			
3	UNBILLED REVENUE	40,159	4,651,000			0.1158
4	UNBILLED REV - UNCOLLECTIBLE		-28,000			
5						
6	WASHINGTON					
7	02LNX00109 - REF/NREF ADV +		1,715			
8	02NETMT135 - WA RES NET MTR	13,159	1,290,703	1,187	11,086	0.0981
9	02OALTB15R - WA OUTD AR LGT	930	143,785	1,021	911	0.1546
10	02RESD0016 - WA RES SRVC	1,526,978	139,840,256	101,802	14,999	0.0916
11	02RESD0017 - BILL ASSISTANC	83,924	7,701,465	5,327	15,754	0.0918
12	02RESD0018 - WA 3 PHASE RES	2,132	214,603	78	27,333	0.1007
13	02RESD018X - WA 3 PHASE RES	300	29,624	12	25,000	0.0987
14	02RGNSB024 - WA SMALL GEN	20,859	2,403,776	3,430	6,081	0.1152
15	02RGNSB036 - RES LRG GEN SVC	1,728	124,882	2	864,000	0.0723
16	02RNM24135 - RES NET MTR	239	25,564	30	7,967	0.1070
17	REVENUE - ACCT ADJ		-9,616,349			
18	REVENUE ADJ - DEF NPC		63,916			
19	ALT REVENUE PROGRAM ADJ		-8,218,174			
20	DSM REVENUE - RESIDENTIAL		4,266,925			
21	BLUE SKY REV - RESIDENTIAL		148,960			
22	UNBILLED REVENUE	4,410	5,074,000			1.1506
23	UNBILLED REV - UNCOLLECTIBLE		-24,000			
24						
25	WYOMING					
26	05LNX00102 - LINE EXT 80% GTY		723			
27	05NETMT135 - EXP PARTIAL REQ	2,082	240,739	220	9,464	0.1156
28	05OALT015R - OUTD AR LGT SR	821	114,512	971	846	0.1395
29	05RESD0002 - WY RES SRVC	898,279	95,745,797	102,250	8,785	0.1066
30	05RGNSV025 - WY SMALL GEN	9,368	1,123,451	1,536	6,099	0.1199
31	09OALT207R - SECURITY AR LG		-78			
32	REVENUE - ACCT ADJ		407,880			
33	INCOME TAX DEFERRAL ADJ		556,518			
34	REVENUE ADJ - DEF NPC		-33,044			
35	DSM REVENUE - RESIDENTIAL		1,513,434			
36	DSM REVENUE - RES GEN SVC		35,795			
37	BLUE SKY REV - RESIDENTIAL		11,465			
38	UNBILLED REVENUE	12,828	1,328,000			0.1035
39	UNBILLED REV - UNCOLLECTIBLE		-23,000			
40	05RESD0002 - WY RES SRVC	115,513	12,466,911	12,514	9,231	0.1079
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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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	05RGNSV025 - WY SMALL GEN	478	76,915	146	3,274	0.1609
2	09OALT207R - SECURITY AR LG	68	16,141	82	829	0.2374
3	05LNX00109 - REF/NREF ADV +		359			
4	05NETMT135 - EXP PARTIAL REQ	499	56,803	42	11,881	0.1138
5	05OALT015R - OUTD AR LGT SR		17			
6	09RES00002			1		
7	09RESD0002			4		
8	DSM REVENUE - RESIDENTIAL		149,520			
9	DSM REVENUE - RES GEN SVC		3,489			
10	BLUE SKY REV - RESIDENTIAL		20,342			
11	UNBILLED REVENUE	-1,020	-111,000			0.1088
12						
13	LESS MULTIPLE BILLINGS			-125,384		
14						
15	TOTAL RESIDENTIAL SALES	16,668,416	1,815,760,353	1,681,634	9,912	0.1089
16						
17	COMMERCIAL SALES					
18	CALIFORNIA					
19	06GNSV0025 - CA GEN SRVC	53,118	9,579,774	6,547	8,113	0.1803
20	06GNSV025F - GEN SRVC-< 20	921	181,643	85	10,835	0.1972
21	06GNSV0A32 - GEN SRVC-20 KW	85,913	13,289,482	1,072	80,143	0.1547
22	06LGSV048T - LRG GEN SERV	27,778	2,854,691	8	3,472,250	0.1028
23	06NMT48135 - GEN SVC NET	2,697	270,619	1	2,697,000	0.1003
24	06LGSV0A36 - LRG GEN SRVC-O	61,648	8,095,749	151	408,265	0.1313
25	06LNX00102 - LINE EXT 80% GTY		2,785			
26	06LNX00109 - REF/NREF ADV +		116,858			
27	06LNX00311 - LINE EXT 80% GTY		28,229			
28	06LNX00312 - CA IRG LINE EXT		2,617			
29	06NMT36135 - GEN SVC NET	2,759	372,431	6	459,833	0.1350
30	06OALT015N - OUTD AR LGT SR	645	187,532	467	1,381	0.2907
31	06RCFL0042 - AIRWAY & ATHLE	155	35,573	37	4,189	0.2295
32	06NMT25135 - GEN SVC NET	123	23,967	25	4,920	0.1949
33	06NMT32135 - GEN SVC NET	1,985	339,240	26	76,346	0.1709
34	REVENUE - ACCT ADJ		-121,540			
35	INCOME TAX DEFERRAL ADJ		-1,207,583			
36	DSM REVENUE - COMMERCIAL		969,334			
37	BLUE SKY REV - COMMERCIAL		2,542			
38	OTHER CUST RETAIL REV		27,894			
39	UNBILLED REVENUE	83	96,000			1.1566
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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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	IDAHO					
2	07CISH0019 - COMM & IND SPA	5,011	422,586	85	58,953	0.0843
3	07GNSV0006 - GEN SRVC-LRG P	247,330	19,777,516	1,030	240,126	0.0800
4	07GNSV0009 - GEN SRVC-HI VO	41,868	2,602,114	2	20,934,000	0.0622
5	07GNSV0023 - GEN SRVC-SML P	156,930	15,327,910	7,145	21,964	0.0977
6	07GNSV0035 - GEN SRVCOPTION	273	21,739	2	136,500	0.0796
7	07GNSV006A - GEN SRVC-LRG P	22,920	1,965,011	176	130,227	0.0857
8	07GNSV023A - GEN SRVC-SML P	27,252	2,643,564	1,282	21,257	0.0970
9	07GNSV023F - GEN SRVC SML P	6	1,683	4	1,500	0.2805
10	07LNX00010 - MNTHLY 80%GUAR		18,736			
11	07LNX00035 - ADV 80%MO GUAR		238,488			
12	07LNX00040 - ADV+REFCHG+80%		37,305			
13	07OALT007N - SECURITY AR LG	247	95,495	168	1,470	0.3866
14	07OALT07AN - SECURITY AR LG	10	3,862	10	1,000	0.3862
15	07LNX00312 - ID LINE EXT		17,694			
16	07NMT06135 - ID NET MTR - LG	1,667	136,778	4	416,750	0.0821
17	07NMT23135 - ID NET MTR -	1,175	93,549	32	36,719	0.0796
18	07LNX00015 - ANNUAL 80% GTY		485			
19	07LNX00311 - LINE EXT 80% GTY		34,378			
20	07LNX00300 - 80% MONTHLY MIN		4,049			
21	REVENUE - ACCT ADJ		-158,391			
22	INCOME TAX DEFERRAL ADJ		-35,510			
23	DSM REVENUE - COMMERCIAL		1,103,786			
24	BLUE SKY REV - COMMERCIAL		891			
25	UNBILLED REVENUE	7,872	642,000			0.0816
26						
27	OREGON					
28	01COST0023 - OR GEN SRV	1,025,836	61,109,229			0.0596
29	01COST0048 - 01LGSV0048	1,112,645	54,828,942			0.0493
30	01COST023F - OR GEN SRV	3,003	190,220			0.0633
31	01COSTB023 - OR GEN SRV	24,832	1,502,746			0.0605
32	01COSTEV45 - ELECT VEHICLE	181	11,257			0.0622
33	01COSTL028 - OR LRG SRV	-72	-2,453			0.0341
34	01COSTL030 - OR LRG GEN SRV	1,124,721	59,530,529			0.0529
35	01COSTS028 - OR GEN SERV	1,927,277	118,905,766			0.0617
36	01GNSB0023 - OR GEN SRV BPA		1,545,369	2,840		
37	01GNSB0028 - OR GEN SRV, BPA		1,721,490	288		
38	01GNSB023T - OR GEN SRV - TOU		24,662	45		
39	01GNSEV45T - ELECT VEHICLE		39,137	16		
40	01GNSV0023 - OR GEN SRV, < 30		51,436,098	58,967		
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	01GNSV0028 - OR GEN SRV > 30		51,799,330	9,004		
2	01GNSV023F - OR GEN SRV - FLAT	10,779	1,663,217	782	13,784	0.1543
3	01GNSV023M - OR GEN SRV,	78	11,355	2	39,000	0.1456
4	01GNSV023T - OR GEN SRV, TOU		143,714	188		
5	01GNSV0723 - OR GEN SVC DIR		5,860	2		
6	01HABT0023 - OR HABITAT	3,442	207,226			0.0602
7	01HABTB023 - OR HABITAT	7	443			0.0633
8	01LGSB0030 - GEN DEL SRV, > 200		861,092	21		
9	01LGSV0028 - OR LRG GEN SRV <		-1,805			
10	01LGSV0030 - OR LRG GEN SRV >		27,101,958	653		
11	01LGSB0048 - LG GEN SVC > 1000		16,200,470	92		
12	01LGSV048M - LRG GEN SRVC 1	61,439	3,731,108	1	61,439,000	0.0607
13	01LNX00100 - LINE EXT 60% GTY		4,189			
14	01LNX00102 - LINE EXT 80% GTY		930,703			
15	01LNX00103 - LINE EXT 80% GTY		6,936			
16	01LNX00105 - CNTRCT $ MIN GTY		11,841			
17	01LNX00109 - REF/NREF ADV +		1,254,885			
18	01LNX00110 - REF/NREF ADV +		8,348			
19	01LNX00311 - LINE EXT 80% GTY		227,261			
20	01LNX00312 - OR IRG LINE EXT		1,496			
21	01LNX00120 - LINE EXT 60% GTY		1,202			
22	01LNX00300 - LINE EXT 80% GTY		308,225			
23	01LPRS047M - PART REQ SRVC	35,804	3,522,825	5	7,160,800	0.0984
24	01NM23T135 - OR NET MTR TOU		1,487	1		
25	01NMT23135 - OR NET MTR, GEN,		353,883	429		
26	01NMT28135 - OR NET MTR, GEN,		1,639,713	235		
27	01NMT30135 - OR NET MTR, GEN,		1,369,084	32		
28	01NMT48135 - NET MTR GEN SVC		499,504	4		
29	01NMTEV45T - OR NET MTR, EV		-725			
30	01OALT015N - OUTD AR LGT NR	5,213	754,282	2,730	1,910	0.1447
31	01OALTB15N - OR OUTD AR LGT	1,366	225,878	1,005	1,359	0.1654
32	01PTOU0023 - OR GEN SRV, TOU	2,808	166,652			0.0593
33	01PTOUB023 - OR GEN SRV, TOU	403	24,704			0.0613
34	01RCFL0054 - REC FIELD LGT	1,458	140,169	105	13,886	0.0961
35	01RENW0023 - OR RENW USAGE	13,964	847,837			0.0607
36	01RENWB023 - OR RENEWABLE	181	10,422			0.0576
37	01STDAY023 - OR DAY STD OFR,	3,541	228,033			0.0644
38	01STDAY028 - OR DAY STD OFF,	12,797	830,083			0.0649
39	01STDAY030 - OR STD DAY OFF,	5,348	309,206			0.0578
40	01VIR23136 - OR VOL INCENTIVE		177,940	122		
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
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1	01VIR28136 - OR VOL INCENTIVE >		533,681	89		
2	01VIR30136 - OR VOL INCENTIVE >		267,302	7		
3	01VIR48136 - OR VOL INCENTIVE >		110,455	1		
4	01ZZMERGCR - MERGER CREDITS		62			
5	01LGSB0048 - LG GEN SVC >		77,015	1		
6	01LGSV028M - OR LGSV, <1000	487	43,551	1	487,000	0.0894
7	01GNSV0728 - OR GEN SVC DIR		38,004	2		
8	01GNSV0730 - OR GEN SVC DIR		1,661,406	14		
9	01GNSV0748 - LG GEN SVC DIR		8,385,483	3		
10	REVENUE - ACCT ADJ		-1,045,125			
11	OR GAIN ON SALE OF ASSET		15,978			
12	INCOME TAX DEFERRAL ADJ		200,893			
13	DSM REVENUE - COMMERCIAL		12,093,786			
14	BLUE SKY REV - COMMERCIAL		759,886	101		
15	SOLAR FEED-IN REVENUE		1,710,007			
16	COMMUNITY SOLAR REVENUE		41,114			
17	UNBILLED REVENUE	39,305	2,713,000			0.0690
18						
19	UTAH					
20	08ABL-NRES - APPLICANT BUILT		1,303			
21	08ABTCLXGN - LINE EXT 80%		3,864			
22	08CFR00051 - MTH FAC SRVCHG		33,483			
23	08CFR00052 - ANN FAC SVCCHG		2			
24	08CGM06136 - UT NET MTR	1,065	114,689	2	532,500	0.1077
25	08CGM23136 - UT NET MT SM GEN	210	21,281	8	26,250	0.1013
26	08CGN08136 - UT NET MTR GEN	1,346	127,011	1	1,346,000	0.0944
27	08CGN06136 - UT GEN SVC	4,529	462,369	17	266,412	0.1021
28	08CGN23136 - UT NET MTR SMALL	919	86,473	37	24,838	0.0941
29	08CGN6A136 - UT GEN SVC TRAN	262	25,073	1	262,000	0.0957
30	08COOLKPRN - A/C DIRECT LOAD		35	2,234		
31	08GNSV0006 - GEN SRVC-DISTR	4,991,880	407,124,779	11,243	443,999	0.0816
32	08GNSV0009 - GEN SRVC-HI VO	862,835	48,229,220	42	20,543,690	0.0559
33	08GNSV0023 - GEN SRVC-DISTR	1,241,510	120,457,881	74,122	16,750	0.0970
34	08GNSV006A - GEN SRVC-ENERG	245,369	28,309,110	1,950	125,830	0.1154
35	08GNSV006B - GEN SRVC-DEM&	3,270	313,077	14	233,571	0.0957
36	08GNSV006M - MNL DIST VOLTG	60	4,475	2	30,000	0.0746
37	08GNSV009A - GEN SRVC HI VO	22,540	1,480,551	2	11,270,000	0.0657
38	08GNSV009M - MANL HIGH VOLT	236,384	13,174,610	1	236,384,000	0.0557
39	08GNSV023F - GEN SRVC FIXED	1,307	182,672	129	10,132	0.1398
40	08GNSV023M - GNSV DIST VOLT	245	18,124	3	81,667	0.0740
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
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1	08GNSV06AM - MNL ENERGY TOD	80	17,622	1	80,000	0.2203
2	08GNSV06MN - GNSV DIST VOLT	36,945	2,916,357	640	57,727	0.0789
3	08LNX00002 - MTHLY 80% GUAR		711,182			
4	08LNX00004 - ANNUAL 80%GUAR		52,594			
5	08LNX00006 - FIXD MTHLY MIN		2,847			
6	08LNX00008 - ANNUALMIN GUAR		350			
7	08LNX00014 - 80% MIN MNTHLY		1,990,862			
8	08LNX00017 - ADV/REF&80%ANN		321,880			
9	08LNX00158 - ANNUALCOST MTH		31,062			
10	08LNX00300 - LINE EXT 80% PLUS		186,737			
11	08LNX00310 - IRR, 80% ANNUAL		68,315			
12	08LNX00312 - UT IRG LINE EXT		13,022			
13	08NMT06135 - UT NET MTR GEN	123,797	10,411,052	267	463,659	0.0841
14	08NMT08135 - NET MTR GEN SVC	57,651	4,355,700	11	5,241,000	0.0756
15	08NMT23135 - UT NET MTR, GEN,	9,741	1,020,794	819	11,894	0.1048
16	08NMT6A135 - NET MTR GEN SVC	10,517	1,360,824	89	118,169	0.1294
17	08OALT007N - SECURITY AR LG	7,230	1,648,722	3,861	1,873	0.2280
18	08POLE0075 - POLES W/LIGHT		129	1		
19	08PRSV031M - BKUP MNT&SUPPL	134,486	8,265,787	4	33,621,500	0.0615
20	08PTLD000N - POST TOP LIGHT	6	452	2	3,000	0.0753
21	08REFS032M - UT RENEWABLE	13,073	842,610			0.0645
22	08SSLR0006 - GENERAL SVC	4,654	459,631	9	517,111	0.0988
23	08SSLR0023 - SMALL GEN SVC	4,043	347,797			0.0860
24	08SSLR006A - GEN SVC TOU	40,024	3,976,960	319	125,467	0.0994
25	08TCVLAACN - UT TCV LNX		3,536			
26	08TCVLNXGN - TCV LNX - 80%		27,146			
27	08TCVLXACN - GAR ADDED		2,197			
28	08TOSS015F - TRAFFIC SIG NM	171	15,277	20	8,550	0.0893
29	08TOSS0015 - TRAF & OTHER S	3,062	316,345	1,067	2,870	0.1033
30	08MONL0015 - MTR OUTDONIGHT	14,554	1,049,399	538	27,052	0.0721
31	08LNX00311 - LINE EXT 80%		291,799			
32	08GNSV0008 - UT GEN SVC TOU >	915,089	64,836,573	127	7,205,425	0.0709
33	08GNSV008M - UT GEN SVC TOU >	16,898	1,343,144	3	5,632,667	0.0795
34	REVENUE - ACCT ADJ		-1,600,450			
35	REVENUE ADJ - DEF NPC		3,097,804			
36	DSM REVENUE - COMMERCIAL		4,684,682			
37	BLUE SKY REV - COMMERCIAL		443,358			
38	SOLAR FEED-IN REVENUE		2,367,741			
39	UNBILLED REVENUE	47,985	4,289,000			0.0894
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	WASHINGTON					
2	02GN24EV45 - WA ELECTRIC		139			
3	02GNSB0024 - WA GEN SRVC DO	28,242	2,643,931	1,518	18,605	0.0936
4	02GNSB024F - GEN SRVC DOM/F	153	19,205	6	25,500	0.1255
5	02GNSB24FP - WA GEN SVC	149	66,245	72	2,069	0.4446
6	02GNSV0024 - WA GEN SRVC	481,488	42,471,530	14,410	33,413	0.0882
7	02GNSV024F - WA GEN SRVC-FL	1,070	145,497	104	10,288	0.1360
8	02LGSB0036 - LRG GEN SVC IRG	50,588	3,951,952	87	581,471	0.0781
9	02LGSV0036 - WA LRG GEN SRV	775,889	58,293,473	874	887,745	0.0751
10	02LGSV048T - LRG GEN SRVC 1	182,073	12,972,346	36	5,057,583	0.0712
11	02LNX00102 - LINE EXT 80% GTY		56,006			
12	02LNX00103 - LINE EXT 80% GTY		119,754			
13	02LNX00105 - CNTRCT $ MIN GTY		2,011			
14	02LNX00109 - REF/NREF ADV +		297,156			
15	02LNX00110 - REF/NREF ADV +		32,999			
16	02LNX00112 - YR INCURRED CH		669			
17	02LNX00300 - LINE EXT 80% GTY		15,986			
18	02LNX00310 - IRG, 80% ANNUAL		1,928			
19	02LNX00311 - LINE EXT 80% GTY		53,743			
20	02LNX00312 - WA IRG LINE EXT		14,333			
21	02NMB24135 - WA NET METERING	100	13,702	20	5,000	0.1370
22	02OALT015N - WA OUTD AR LGT	1,424	204,978	766	1,859	0.1439
23	02OALTB15N - WA OUTD AR LGT	504	79,165	464	1,086	0.1571
24	02RCFL0054 - WA REC FIELD L	292	26,191	27	10,815	0.0897
25	02RFNDCEN - CENTRALIA RFND		-1			
26	02NMT24135 - NET MTR, WA	4,184	377,256	95	44,042	0.0902
27	02NMT36135 - WA NET MTR LRG	12,533	1,009,040	16	783,313	0.0805
28	02NMT48135 - WA LG SVC NET	10,901	765,701	2	5,450,500	0.0702
29	REVENUE - ACCT ADJ		-8,247,772			
30	REVENUE ADJ - DEF NPC		63,079			
31	ALT REVENUE PROGRAM ADJ		-7,194,658			
32	DSM REVENUE - COMMERCIAL		3,409,065			
33	BLUE SKY REV - COMMERCIAL		18,143	2		
34	UNBILLED REVENUE	-3,088	-178,000			0.0576
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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 2019/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	WYOMING					
2	05CHCK000N - WY NRES CHECK			1		
3	05GNSV0025 - WY GEN SRVC	227,847	21,761,916	18,005	12,655	0.0955
4	05GNSV0028 - GEN SVC > 15 KW	846,815	69,805,696	3,169	267,218	0.0824
5	05GNSV025F - GEN SRVC-FL RA	987	154,295	173	5,705	0.1563
6	05LGSV0046 - WY LRG GEN SRV	151,675	10,673,105	13	11,667,308	0.0704
7	05LGSV048T - LRG GENSRV TIM	11,886	849,341	1	11,886,000	0.0715
8	05LNX00100 - LINE EXT 60% GTY		13,622			
9	05LNX00102 - LINE EXT 80% GTY		506,511			
10	05LNX00103 - LINE EXT 80% GTY		1,255			
11	05LNX00105 - CNTRCT $ MIN GTY		5,410			
12	05LNX00109 - REF/NREF ADV +		330,803			
13	05LNX00110 - REF/NREF ADV +		2,610			
14	05LNX00114 - TEMP SVC 12MO>		134			
15	05NMT25135 - WY NET MTR, GEN,	403	37,376	33	12,212	0.0927
16	05NMT28135 - NET MTR SMALL	8,039	664,563	23	349,522	0.0827
17	05OALT015N - OUTD AR LGT SR	2,546	354,275	1,566	1,626	0.1391
18	05RCFL0054 - WY REC FIELD L	969	65,079	60	16,150	0.0672
19	09OALT207N - SECURITY AR LG		-7			
20	05LNX00300 - LINE EXT 80% GTY		131,021			
21	05LNX00310 - LINE EXT		1,628			
22	05LNX00311 - LINE EXT 80% GTY		39,540			
23	05LNX00312 - WY IRG LINE EXT		5,646			
24	REVENUE - ACCT ADJ		476,506			
25	INCOME TAX DEFERRAL ADJ		798,601			
26	REVENUE ADJ - DEF NPC		-47,418			
27	DSM REVENUE - SM		2,559,184			
28	DSM REVENUE - LG COMMERCIAL		31,998			
29	BLUE SKY REV - COMMERCIAL		1,340			
30	UNBILLED REVENUE	5,483	412,000			0.0751
31	05GNSV0025 - WY GEN SRVC	33,382	3,130,358	2,435	13,709	0.0938
32	05GNSV0028 - GEN SVC > 15 KW	90,549	7,433,956	374	242,110	0.0821
33	05GNSV025F - GEN SRVC-FL RA	199	24,561	33	6,030	0.1234
34	05LNX00102 - LINE EXT 80% GTY		114,456			
35	05LNX00103 - LINE EXT 80% GTY		1,044			
36	05LNX00109 - REF/NREF ADV +		132,650			
37	05LNX00110 - REF/NREF ADV +		760			
38	05NMT25135 - WY NET MTR, GEN,	84	6,825	4	21,000	0.0813
39	05NMT28135 - NET MTR SMALL	477	39,366	3	159,000	0.0825
40	09OALT207N - SECURITY AR LG	274	56,384	140	1,957	0.2058
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	09MONL0213 - WY MTR OUTDOOR	287	16,383	12	23,917	0.0571
2	05LNX00300 - LINE EXT 80% GTY		5,533			
3	05LNX00311 - LINE EXT 80% GTY		4,355			
4	DSM REVENUE - SM		407,391			
5	BLUE SKY REV - COMMERCIAL		767			
6	UNBILLED REVENUE	1,175	98,000			0.0834
7						
8	LESS MULTIPLE BILLINGS			-24,101		
9						
10	TOTAL COMMERCIAL SALES	18,150,545	1,547,127,608	214,182	84,744	0.0852
11						
12	INDUSTRIAL SALES					
13	CALIFORNIA					
14	06GNSV0025 - CA GEN SRVC	515	97,209	82	6,280	0.1888
15	06GNSV0A32 - GEN SRVC-20 KW	2,609	437,371	23	113,435	0.1676
16	06LGSV048T - LRG GEN SERV	48,066	5,089,527	10	4,806,600	0.1059
17	06LGSV0A36 - LRG GEN SRVC-O	5,806	831,922	13	446,615	0.1433
18	REVENUE - ACCT ADJ		-4,119			
19	INCOME TAX DEFERRAL ADJ		-294,813			
20	DSM REVENUE - INDUSTRIAL		211,145			
21	BLUE SKY REV - INDUSTRIAL		57			
22	OTHER CUST RETAIL REV		12,200			
23	UNBILLED REVENUE	-400	-103,000			0.2575
24						
25	IDAHO					
26	07CFR00001 - MTH FACILITY S		2,217			
27	07CISH0019 - COMM & IND SPA	18	1,693	1	18,000	0.0941
28	07GNSV0006 - GEN SRVC-LRG P	86,800	6,090,305	101	859,406	0.0702
29	07GNSV0009 - GEN SRVC-HI VO	70,669	4,580,013	14	5,047,786	0.0648
30	07GNSV0023 - GEN SRVC-SML P	15,768	1,471,491	309	51,029	0.0933
31	07GNSV006A - GEN SRVC-LRG P	3,180	260,931	23	138,261	0.0821
32	07GNSV023A - GEN SRVC-SML P	2,077	211,352	138	15,051	0.1018
33	07GNSV023S - ID TRAFFIC	5	607	1	5,000	0.1214
34	07LNX00108 - ANN COST MTHLY		1,996			
35	07LNX00311 - LINE EXT 80% GTY		24			
36	07OALT007N - SECURITY AR LG	13	4,911	16	813	0.3778
37	07OALT07AN - SECURITY AR LG		221	1		
38	07SPCL0001	1,479,600	89,981,592	1	1,479,600,000	0.0608
39	07SPCL0002	93,929	5,584,278	1	93,929,000	0.0595
40	REVENUE - ACCT ADJ		12,700			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	INCOME TAX DEFERRAL ADJ		-127,568			
2	DSM REVENUE - INDUSTRIAL		559,684			
3	BLUE SKY REV - INDUSTRIAL		4			
4	UNBILLED REVENUE	-104,317	-6,112,000			0.0586
5						
6	OREGON					
7	01COST0023 - OR GEN SRV, COST	17,919	1,072,730			0.0599
8	01COST0048 - 01LGSV0048	1,273,163	63,727,562			0.0501
9	01COST023F - OR GEN SRV -	1	66			0.0660
10	01COSTB023 - OR GEN SRV,	111	6,726			0.0606
11	01COSTL030 - OR LRG GEN SRV,	180,706	9,596,480			0.0531
12	01COSTS028 - OR GEN SERV,	88,092	5,421,632			0.0615
13	01GNSB0023 - OR GEN SRV, BPA,		7,387	11		
14	01GNSB0028 - OR GEN SRV, BPA,		8,549	2		
15	01GNSV0023 - OR GEN SRV, < 30		937,394	960		
16	01GNSV0028 - OR GEN SRV > 30		3,051,305	423		
17	01GNSV023F - OR GEN SRV - FLAT	2	678	2	1,000	0.3390
18	01GNSV023M - OR GEN SRV,		311	1		
19	01GNSV023T - OR GEN SRV, TOU		2,764	3		
20	01GNSV0748 - LG GEN SVC DIR		1,524,624	3		
21	01HABT0023 - OR HABITAT	58	2,907			0.0501
22	01LGSV0030 - OR LRG GEN SRV, >		6,515,907	129		
23	01LGSV0048 - 1000KW AND OVR		20,744,433	81		
24	01LGSV048M - LRG GEN SRVC 1	79,237	5,623,063	3	26,412,333	0.0710
25	01LNX00102 - LINE EXT 80% GTY		130,335			
26	01LNX00109 - REF/NREF ADV +		496			
27	01LNX00300 - LINE EXT 80% GTY		12,758			
28	01LPRS047M - PART REQ SRVC	2,728	1,068,196	1	2,728,000	0.3916
29	01NMT23135 - OR NET MTR, GEN,		3,474	5		
30	01NMT28135 - OR NET MTR, GEN,		36,961	5		
31	01NMT30135 - OR NET MTR, GEN,		87,609	3		
32	01OALT015N - OUTD AR LGT NR	266	37,376	120	2,217	0.1405
33	01OALTB15N - OR OUTD AR LGT	3	393	3	1,000	0.1310
34	01PTOU0023 - OR GEN SRV, TOU	45	2,879			0.0640
35	01RENW0023 - OR RENW USAGE	52	3,188			0.0613
36	01STDAY028 - OR DAY STD OFF,	172	12,005			0.0698
37	01VIR23136 - OR VOLUME		854	1		
38	01VIR28136 - OR VOLUME		12,419	2		
39	01VIR30136 - OR VOLUME		62,555	1		
40	REVENUE - ACCT ADJ		-1,123,729			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
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1	OR GAIN ON SALE OF ASSET		5,078			
2	INCOME TAX DEFERRAL ADJ		63,857			
3	DSM REVENUE - INDUSTRIAL		1,050,078			
4	BLUE SKY REV - INDUSTRIAL		441,826	23		
5	SOLAR FEED-IN REVENUE		555,573			
6	COMMUNITY SOLAR REVENUE		12,363			
7	UNBILLED REVENUE	-18,728	-861,000			0.0460
8						
9	UTAH					
10	08CFR00051 - MTH FAC SRVCHG		18,115			
11	08CGN06136 - UT GEN SVC	728	57,861			0.0795
12	08EFOP0021 - ELEC FURNACE O	254	15,632			0.0615
13	08EFOP021M - ELEC FURNACE O	1,002	141,601	2	501,000	0.1413
14	08GNSV0006 - GEN SRVC-DISTR	603,315	51,239,228	958	629,765	0.0849
15	08GNSV0009 - GEN SRVC-HI VO	2,914,667	159,058,471	103	28,297,738	0.0546
16	08GNSV0023 - GEN SRVC-DISTR	53,175	5,157,782	3,148	16,892	0.0970
17	08GNSV006A - GEN SRVC-ENERG	44,646	5,392,827	229	194,961	0.1208
18	08GNSV006B - GEN SRVC-DEM&	7	2,756			0.3937
19	08GNSV009A - GEN SRVC HI VO	17,623	1,569,320	7	2,517,571	0.0890
20	08GNSV009M - MANL HIGH VOLT	678,976	35,477,102	11	61,725,091	0.0523
21	08GNSV023F - GEN SRVC FIXED	4	2,557	1	4,000	0.6393
22	08GNSV06MN - GNSV DIST VOLT	1,039	92,338	22	47,227	0.0889
23	08LNX00002 - MTHLY 80% GTY		744,979			
24	08LNX00014 - 80% MIN MNTHLY		10,323			
25	08LNX00017 - ADV/REF&80%ANN		638			
26	08LNX00311 - LINE EXT 80% GTY		5			
27	08LNX00300 - LINE EXT 80% PLUS		49,310			
28	08OALT007N - SECURITY AR LG	948	199,529	394	2,406	0.2105
29	08TOSS0015 - TRAF & OTHER S	48	4,640	12	4,000	0.0967
30	08MONL0015 - MTR OUTDONIGHT	13	2,296	6	2,167	0.1766
31	08NMT06135 - UT NET MTR GEN	2,230	208,871	6	371,667	0.0937
32	08NMT23135 - UT NET MTR, GEN,	177	20,298	17	10,412	0.1147
33	08NMT6A135 - NET MTR GEN SVC	4,051	560,063	13	311,615	0.1383
34	08PRSV031M - BKUP MNT&SUPPL	49,625	3,757,081	3	16,541,667	0.0757
35	08SPCL0001	602,656	30,565,663	1	602,656,000	0.0507
36	08SPCL0002	809,246	36,340,880	1	809,246,000	0.0449
37	08SPCL0003	1,287,046	67,226,917	1	1,287,046,000	0.0522
38	08SSLR0006 - GEN SVC SUBSCR	268	22,291	2	134,000	0.0832
39	08SSLR0023 - SMALL GEN SVC	153	17,075	18	8,500	0.1116
40	08SSLR006A - GEN SVC TOU	11,084	1,038,931	30	369,467	0.0937
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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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	08GNSV06AM - MNL ENERGY TOD	283	33,798	2	141,500	0.1194
2	08GNSV0008 - UT GEN SVC TOU >	984,500	71,986,863	101	9,747,525	0.0731
3	08GNSV008M - UT GEN SVC TOU >	27,264	2,146,613	4	6,816,000	0.0787
4	REVENUE - ACCT ADJ		-258,416			
5	REVENUE ADJ - DEF NPC		2,734,869			
6	DSM REVENUE - INDUSTRIAL		4,135,250			
7	BLUE SKY REV - INDUSTRIAL		116,729	7		
8	SOLAR FEED-IN REVENUE		2,090,339			
9	UNBILLED REVENUE	-83,578	-6,231,000			0.0746
10						
11	WASHINGTON					
12	02GNSB0024 - WA GEN SRVC DO	885	93,109	43	20,581	0.1052
13	02GNSB24FP - WA GEN SVC	3	481	1	3,000	0.1603
14	02GNSV0024 - WA GEN SRVC	14,843	1,328,298	328	45,253	0.0895
15	02GNSV024F - WA GEN SRVC-FL	33	8,627	4	8,250	0.2614
16	02LGSV0036 - WA LRG GEN SRV	98,809	7,745,502	95	1,040,095	0.0784
17	02LGSV048T - LRG GEN SRVC 1	660,419	40,313,189	29	22,773,069	0.0610
18	02LNX00103 - LINE EXT 80% GTY		31,621			
19	02LNX00300 - LINE EXT 80% GTY		9,016			
20	02NMT24135 - NET MTR, WA	11	1,294	1	11,000	0.1176
21	02OALT015N - WA OUTD AR LGT	96	12,700	37	2,595	0.1323
22	02OALTB15N - WA OUTD AR LGT	27	4,019	14	1,929	0.1489
23	02PRSV47TM - LRG PART REQMT	2,377	343,720	1	2,377,000	0.1446
24	02LGSB0036 - LRG GEN SVC IRG	1,437	167,923	9	159,667	0.1169
25	REVENUE - ACCT ADJ		-2,461,355			
26	REVENUE ADJ - DEF NPC		27,593			
27	ALT REVENUE PROGRAM ADJ		-1,494,763			
28	DSM REVENUE - INDUSTRIAL		1,363,237			
29	BLUE SKY REV - INDUSTRIAL		11	1		
30	UNBILLED REVENUE	-1,886	411,000			-0.2179
31						
32	WYOMING					
33	05GNSV0025 - WY GEN SRVC	28,711	2,426,382	1,180	24,331	0.0845
34	05GNSV0028 - GEN SVC > 15 KW	267,109	19,142,713	433	616,880	0.0717
35	05GNSV025F - GEN SRVC-FL RA	26	4,150	8	3,250	0.1596
36	05LGSV0046 - WY LRG GEN SRV	1,689,000	109,309,343	59	28,627,119	0.0647
37	05LGSV046M - WY LRG GEN SRV	9,761	729,408	1	9,761,000	0.0747
38	05LGSV048M - TOU>1000KW MAN	245,448	13,689,662	1	245,448,000	0.0558
39	05LGSV048T - LRG GENSRV TIM	1,875,002	103,649,692	11	170,454,727	0.0553
40	05LNX00100 - LINE EXT 60% GTY		47,374			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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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	05LNX00102 - LINE EXT 80% GTY		1,095,342			
2	05LNX00105 - CNTRCT $ MIN GTY		45,261			
3	05LNX00109 - REF/NREF ADV +		167,837			
4	05LNX00110 - REF/NREF ADV +		569			
5	05LNX00300 - LINE EXT 80% GTY		62,394			
6	05LNX00311 - LINE EXT 80% GTY		17,596			
7	05OALT015N - OUTD AR LGT SR	69	8,720	38	1,816	0.1264
8	05PRSV033M - PART SERV REQ	1,324,577	84,903,997	9	147,175,222	0.0641
9	REVENUE - ACCT ADJ		1,868,963			
10	INCOME TAX DEFERRAL ADJ		3,944,662			
11	REVENUE ADJ - DEF NPC		-234,218			
12	DSM REVENUE - SM INDUSTRIAL		589,785			
13	DSM REVENUE - LG INDUSTRIAL		395,501			
14	BLUE SKY REV - INDUSTRIAL		-15			
15	UNBILLED REVENUE	56,149	3,365,000			0.0599
16	05GNSV0025 - WY GEN SRVC	3,646	349,286	283	12,883	0.0958
17	05GNSV0028 - GEN SVC > 15 KW	68,582	4,711,667	71	965,944	0.0687
18	05GNSV028M - GEN SVC > 15 KW	4,005	236,064	3	1,335,000	0.0589
19	05LGSV0046 - WY LRG GEN SRV	27,813	1,811,426	3	9,271,000	0.0651
20	05LGSV048M - TOU>1000KW MAN	133,236	8,059,325	2	66,618,000	0.0605
21	05LGSV048T - LRG GENSRV TIM	1,133,288	68,163,237	12	94,440,667	0.0601
22	05LNX00102 - LINE EXT 80% GTY		450,121			
23	05LNX00109 - REF/NREF ADV +		2,009,444			
24	05NMT25135 - WY NET MTR, GEN,	10	809			0.0809
25	05NMT28135 - NET MTR SMALL	34	4,005	1	34,000	0.1178
26	05PRSV033M - PART SERV REQ	89,483	5,509,816	2	44,741,500	0.0616
27	09OALT207N - SECURITY AR LG	3	582	2	1,500	0.1940
28	DSM REVENUE - SM INDUSTRIAL		203,468			
29	DSM REVENUE - LG INDUSTRIAL		684,018			
30	BLUE SKY REV - INDUSTRIAL		29			
31	UNBILLED REVENUE	-23,780	-1,398,000			0.0588
32						
33	LESS MULTIPLE BILLINGS			-870		
34						
35	TOTAL INDUSTRIAL SALES	19,048,841	1,188,343,074	9,427	2,020,668	0.0624
36						
37						
38						
39						
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	IRRIGATION SALES					
2	CALIFORNIA					
3	06APSV0020 - AG PMP SRVC	9,334	1,384,232	748	12,479	0.1483
4	06APSV0115 - CA AGRI PUMP TOU	35	4,862	2	17,500	0.1389
5	06APSV020L - AG PMP SRVC	48,069	7,013,491	591	81,335	0.1459
6	06APSV115L - CA AGRI PUMP TOU	734	104,940	9	81,556	0.1430
7	06LGSV048T - LRG GEN SERV	3,405	373,647	1	3,405,000	0.1097
8	06LNX00103 - LINE EXT 80% GTY		1,207			
9	06LNX00109 - REF/NREF ADV +		409			
10	06LNX00110 - REF/NREF ADV +		32,806			
11	06LNX00310 - IRG, 80% ANNUAL		6,431			
12	06LNX00312 - CA IRG LINE EXT		29,248			
13	06NML20135 - AGRI PUMP-NET	2,149	370,088	24	89,542	0.1722
14	06NMT20135 - AGRI PUMP-NET	173	28,648	10	17,300	0.1656
15	06USBR0020 - KLAM IRG ONPRJ	3,129	573,273	273	11,462	0.1832
16	06USBR0115 - CA AGR PMP TOU	4	2,043	1	4,000	0.5108
17	06USBR020L - KLAM IRG ONPRJ	14,661	2,470,639	344	42,619	0.1685
18	06USBR115L - CA AGR PMP TOU	567	85,379	9	63,000	0.1506
19	REVENUE - ACCT ADJ		-19,620			
20	INCOME TAX DEFERRAL ADJ		-454,004			
21	DSM REVENUE - IRRIGATION		338,227			
22	BLUE SKY REV - IRRIGATION		12			
23	OTHER CUST RETAIL REV		2,871			
24	UNBILLED REVENUE	-952	-76,000			0.0798
25						
26	IDAHO					
27	07APSA010L - IRG & PUMP LG	335,763	30,528,310	2,364	142,032	0.0909
28	07APSA010S - IRG & PUMP SM	5,710	607,966	327	17,462	0.1065
29	07APSAL10X - IRG & PUMP - LG	218,411	20,107,391	1,823	119,809	0.0921
30	07APSAS10X - IRG & PUMP - SM	7,240	804,860	528	13,712	0.1112
31	07APSV006A - LRG POWER OPT	250	25,085	1	250,000	0.1003
32	07APSV023A - SM POWER OPT	211	20,742	4	52,750	0.0983
33	07APSVCNLL - LRG LOAD CANAL	12,571	1,026,551	37	339,757	0.0817
34	07APSVCNLS - SML LOAD CANAL	22	3,912	11	2,000	0.1778
35	07GNSV023A - GEN SRVC-SML P	104	9,405	1	104,000	0.0904
36	07LNX00015 - ANNUAL 80% GTY		71,421			
37	07LNX00035 - ADV 80% MO GTY		2,830			
38	07LNX00040 - ADV+REFCHG+80%		120,907			
39	07LNX00310 - 80% ANNUAL GTY		801			
40	07LNX00312 - ID LINE EXT		50,622			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	07APSN010L - ID LG IRR & PUMP	6,565	583,656	35	187,571	0.0889
2	07APSN010S - IRR, SMALL, 3	18	2,610	3	6,000	0.1450
3	07APSNS10X - IRR, SMALL, 3	226	27,386	17	13,294	0.1212
4	REVENUE - ACCT ADJ		-196,101			
5	INCOME TAX DEFERRAL ADJ		-39,466			
6	DSM REVENUE - IRRIGATION		1,317,344			
7	BLUE SKY REV - IRRIGATION		19			
8	UNBILLED REVENUE	224	22,000			0.0982
9						
10	OREGON					
11	01APSV0041 - AG PMP SRVC BP		1,150,108	2,435		
12	01APSV0215 - OR IRR TOU PILOT		20,817	11		
13	01APSV041L - OR PUMP SRV		1,824,096	704		
14	01APSV041T - AGR PUMP		24,609	53		
15	01APSV041X - AG PMP SRVC		1,026,589	2,464		
16	01APSV41XL - OR PUMP SRV NO		1,545,562	461		
17	01COST0041 -	117,134	7,040,996			0.0601
18	01COST0048 - 01LGSV0048	110,150	5,559,706			0.0505
19	01COST0215 - OR TOU PILOT	3,726	166,330			0.0446
20	01CSTUSB41 - USBR IRR	63,085	3,791,604			0.0601
21	01GNSV023T - OR GEN SRV, TOU		1,839	1		
22	01HABIT041 - 01APSV0041 AG	10	628			0.0628
23	01LGSB0048 - LG GEN SVC >		829,516	3		
24	01LGSV0048 - 1000KW AND OVR		1,203,135	3		
25	01LNX00103 - LINE EXT 80% GTY		35,262			
26	01LNX00109 - REF/NREF ADV +		363			
27	01LNX00110 - REF/NREF ADV +		101,424			
28	01LNX00310 - LINE EXT		13,768			
29	01PTOU0023 - OR GEN SRV, TOU	49	2,745			0.0560
30	01PTOU0041 - 01APSV0041 AG	511	30,313			0.0593
31	01RENEW041 - 01APSV0041 AG	149	9,095			0.0610
32	01STDAY041 - DAILY STANDARD	121	6,918			0.0572
33	01USBR0215 - OR IRG TOU PILOT		123,374	72		
34	01USBRGV41 - IRG TOU W/O BPA		62,991	9		
35	01USBROF41 - KLAMATH BASIN		1,085,545	481		
36	01USBRON41 - KLAMATH BASIN		1,548,154	1,113		
37	01VIR41136 - OR VOL		47,409	26		
38	01VRU41136 - OR VOL INCENTIVE		286,355	104		
39	01VRU41215 - OR VOL INCENTIVE		28,812	6		
40	01LNX00312 - OR IRG LINE EXT		26,397			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	01NMT41135 - NETMTR AG PMP		29,236	30		
2	01NMU41135 - OR NET MTR -		27,096	12		
3	REVENUE - ACCT ADJ		-144,576			
4	OR GAIN ON SALE OF ASSET		110			
5	INCOME TAX DEFERRAL ADJ		12,825			
6	DSM REVENUE - IRRIGATION		610,919			
7	BLUE SKY REV - IRRIGATION		291			
8	SOLAR FEED-IN REVENUE		107,630			
9	COMMUNITY SOLAR REVENUE		2,333			
10	UNBILLED REVENUE	-10,120	181,000			-0.0179
11						
12	UTAH					
13	08APSV0010 - IRR & SOIL DRA	172,333	13,355,183	3,060	56,318	0.0775
14	08APSV10NS - IRR LG SOIL DRAIN	27,968	2,059,511	296	94,486	0.0736
15	08LNX00004 - ANNUAL 80% GTY		9,815			
16	08LNX00014 - 80% MIN MNTHLY		4,845			
17	08LNX00017 - ADV/REF&80%ANN		165,901			
18	08LNX00310 - IRR, 80% ANNUAL		30,405			
19	08LNX00311 - LINE EXT 80% GTY		1,163			
20	08LNX00312 - UT IRG LINE EXT		11,217			
21	08NMT010NS - IRR & SOIL DRAIN	246	22,960	4	61,500	0.0933
22	08NMT10135 - UT IRR_SOIL DRNG	8,072	638,006	62	130,194	0.0790
23	08TCVLAACN - UT TCV LNX		316			
24	08TCVLNAGN - UT LNX ANNUAL		7,961			
25	REVENUE - ACCT ADJ		-6,271			
26	REVENUE ADJ - DEF NPC		91,308			
27	DSM REVENUE - IRRIGATION		137,781			
28	SOLAR FEED-IN REVENUE		69,789			
29	UNBILLED REVENUE	393	24,000			0.0611
30						
31	WASHINGTON					
32	02APSV0040 - WA AG PMP SRVC	90,870	7,590,342	2,800	32,454	0.0835
33	02APSV040X - WA AG PMP SRVC	63,711	5,333,476	2,347	27,146	0.0837
34	02LNX00102 - LINE EXT 80% GTY		2,699			
35	02LNX00103 - LINE EXT 80% GTY		1,483			
36	02LNX00105 - CNTRCT $ MIN GTY		79			
37	02LNX00110 - REF/NREF ADV +		143,814			
38	02LNX00310 - IRG, 80% ANNUAL		6,750			
39	02LNX00312 - WA IRG LINE EXT		33,920			
40	02NMT40135 - WA NET MTR-IRG	168	14,851	9	18,667	0.0884
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
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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	02NMX40135 - WA NET MTR-IRG	41	7,501	6	6,833	0.1830
2	REVENUE - ACCT ADJ		-466,231			
3	REVENUE ADJ - DEF NPC		6,491			
4	ALT REVENUE PROGRAM ADJ		-885,712			
5	DSM REVENUE - IRRIGATION		363,742			
6	BLUE SKY REV - IRRIGATION		524			
7	UNBILLED REVENUE	3,938	1,346,000			0.3418
8						
9	WYOMING					
10	05APS00040 - AG PUMP SVC	16,724	1,433,166	709	23,588	0.0857
11	05APSNS040 - AG PUMP SVC	1,644	135,051	28	58,714	0.0821
12	05LNX00103 - LINE EXT 80% GTY		740			
13	05LNX00109 - REF/NREF ADV +		854			
14	05LNX00110 - REF/NREF ADV +		25,035			
15	05LNX00310 - LINE EXT		870			
16	05LNX00312 - WY IRG LINE EXT		4,139			
17	09APSNS210 - IRR & SOIL DRA	11	1,356	1	11,000	0.1233
18	REVENUE - ACCT ADJ		9,436			
19	INCOME TAX DEFERRAL ADJ		14,920			
20	REVENUE ADJ - DEF NPC		-886			
21	DSM REVENUE - IRRIGATION		-4,237			
22	BLUE SKY REV - IRRIGATION		4			
23	UNBILLED REVENUE	1,352	61,000			0.0451
24	05APS00040 - AG PUMP SVC	132	11,086	6	22,000	0.0840
25	05LNX00103 - LINE EXT 80% GTY		976			
26	05LNX00110 - REF/NREF ADV +		13,855			
27	09APSNS210 - IRR & SOIL DRA	460	43,405	5	92,000	0.0944
28	09APSV0210 - IRR & SOIL DRA	5,528	438,668	96	57,583	0.0794
29	DSM REVENUE - IRRIGATION		18,569			
30	UNBILLED REVENUE	26	2,000			0.0769
31						
32	LESS MULTIPLE BILLINGS			-856		
33						
34	TOTAL IRRIGATION SALES	1,347,055	128,126,030	23,724	56,780	0.0951
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	PUBLIC STREET & HWY LIGHTING					
2	CALIFORNIA					
3	06CUSL053E - SPECIAL CUST O	1,086	192,092	107	10,150	0.1769
4	06CUSL058F - CUST OWND STR	52	10,333	20	2,600	0.1987
5	06SLCO0051 - COMPANY OWNED	687	221,050	77	8,922	0.3218
6	06OALT015N - OUTD AR LGT SR		263	1		
7	REVENUE - ACCT ADJ		-3,856			
8	INCOME TAX DEFERRAL ADJ		-7,806			
9	DSM REVENUE - PSHL		9,326			
10	OTHER CUST RETAIL REV		153			
11	UNBILLED REVENUE	-132	-28,000			0.2121
12						
13	IDAHO					
14	07GNSV023S - ID TRAFFIC	147	17,401	23	6,391	0.1184
15	07SLCO0011 - STR LGT CO-OWN	153	71,941	56	2,732	0.4702
16	07SLCU012E - ENGY STR LGT	434	47,242	51	8,510	0.1089
17	07SLCU012F - FULL MNT STR LGT	1,761	348,215	183	9,623	0.1977
18	07SLCU012P - PART MNT STR LGT	194	27,891	16	12,125	0.1438
19	REVENUE - ACCT ADJ		-2,973			
20	INCOME TAX DEFERRAL ADJ		-183			
21	DSM REVENUE - PSHL		12,482			
22	UNBILLED REVENUE	13	2,000			0.1538
23						
24	OREGON					
25	01COSL0052 - STR LGT SRVC C	364	54,451	35	10,400	0.1496
26	01COST023F - OR GEN SRV	598	37,981			0.0635
27	01CUSL0053 - CUS-OWNED MTRD	497	36,061	72	6,903	0.0726
28	01GNSV023F - OR GEN SRV - FLAT		104,478	14		
29	01CUSL053E - STR LGT SVC	10,544	762,071	225	46,862	0.0723
30	01CUSL053F - STR LGT SRVC C	116	10,945	9	12,889	0.0944
31	01CUSL53E2 - STR LGT SVC	1	59	1	1,000	0.0590
32	01HPSV0051 - HI PRESSURE SO	19,217	3,962,490	751	25,589	0.2062
33	01LEDSL051 - OR LED PILOT	675	232,601	85	7,941	0.3446
34	01MVSL0050 - MERC VAPSTR LG	7,938	997,174	230	34,513	0.1256
35	01OALT015N - OUTD AR LGT NR	35	6,257	18	1,944	0.1788
36	01OALTB15N - OR OUTD AR LGT	7	1,160	9	778	0.1657
37	REVENUE - ACCT ADJ		-17,649			
38	OR GAIN ON SALE OF ASSET		1,019			
39	INCOME TAX DEFERRAL ADJ		1,401			
40	DSM REVENUE - PSHL		187,725			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	SOLAR FEED-IN REVENUE		11,748			
2	COMMUNITY SOLAR REVENUE		136			
3	UNBILLED REVENUE	1,074	169,000			0.1574
4						
5	UTAH					
6	08CFR00012 - STR LGTS		54			
7	08CFR00051 - MTH FAC SRVCHG		4,529			
8	08CFR00062 - STREET LIGHTS		73			
9	08OALT007N - SECURITY AR LG	363	93,722	194	1,871	0.2582
10	08TOSS015F - TRAFFIC SIG NM	1,151	101,248	121	9,512	0.0880
11	08SLCO0011 - STR LGT CO-OWN	13,487	4,076,143	717	18,810	0.3022
12	08TOSS0015 - TRAF & OTHER S	3,138	349,127	1,477	2,125	0.1113
13	08MONL0015 - MTR OUTDONIGHT	849	68,636	95	8,937	0.0808
14	08SLCU012P - STR LGT CUST-O	3,021	374,185	170	17,771	0.1239
15	08SLCU012F - STR LGT CUST-O	951	126,854	67	14,194	0.1334
16	08SLCU012E - DECOR CUST-OWN	41,473	2,642,632	1,004	41,308	0.0637
17	REVENUE - ACCT ADJ		-21,686			
18	REVENUE ADJ - DEF NPC		23,341			
19	DSM REVENUE - PSHL		35,258			
20	SOLAR FEED-IN REVENUE		17,840			
21	UNBILLED REVENUE	-2,392	-276,000			0.1154
22						
23	WASHINGTON					
24	02CFR00012 - STR LGTS		91			
25	02COSL0052 - WA STR LGT SRV	90	18,312	9	10,000	0.2035
26	02CUSL053F - WA STR LGT SRV	2,950	205,219	120	24,583	0.0696
27	02CUSL053M - WA STR LGT SRV	731	50,830	112	6,527	0.0695
28	02SLCO0051 - WA COMPANY ST	3,197	758,342	219	14,598	0.2372
29	02MVSL0057 - WA MERC VAPSTR	1,165	148,853	25	46,600	0.1278
30	REVENUE - ACCT ADJ		-49,424			
31	DSM REVENUE - PSHL		18,829			
32	UNBILLED REVENUE	-487	-54,000			0.1109
33						
34	WYOMING					
35	05COSL0057 - CO-OWND STR LG	238	48,276	15	15,867	0.2028
36	05CUSL0058 - CUST OWND STR	49	2,718	10	4,900	0.0555
37	05CUSL0E58 - WY CUST OWNED	1,079	59,759	33	32,697	0.0554
38	05CUSL0M58 - CUST OWNED ST	44	2,989	3	14,667	0.0679
39	05HPSV0051 - HI PRESSURE SO	5,655	1,039,113	186	30,403	0.1838
40	05MVS00053 - MERCURY VAPOR	3,521	397,679	225	15,649	0.1129
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	05OALT015N - OUTD AR LGT SR	38	4,325	4	9,500	0.1138
2	REVENUE - ACCT ADJ		9,877			
3	INCOME TAX DEFERRAL ADJ		7,221			
4	REVENUE ADJ - DEF NPC		-429			
5	DSM REVENUE - PSHL		49,115			
6	UNBILLED REVENUE	612	88,000			0.1438
7	05HPSV0051 - HI PRESSURE SO		10			
8	09MONL0213 - WY MTR OUTDOOR	29	2,738	1	29,000	0.0944
9	09SLCO0211 - STR LGT CO-OWN	1,496	328,000	51	29,333	0.2193
10	09SLCUP212 - CUST OWNED ST	34	4,829	5	6,800	0.1420
11	09TOSS0213 - WY TRAFFIC &	48	2,361	15	3,200	0.0492
12	DSM REVENUE - PSHL		12,776			
13	UNBILLED REVENUE	-241	-51,000			0.2116
14						
15	LESS MULTIPLE BILLINGS			-3,296		
16						
17	TOTAL PUBLIC STREET & HWY LT	127,750	18,198,044	3,565	35,835	0.1425
18						
19	FORFEITED DISCOUNTS					
20	CALIFORNIA					
21	06LPAY0300 - RES-LATEFEE		187,973			
22	06LPAY0300 - COM-LATEFEE		55,479			
23	06LPAY0300 - IND-LATEFEE		67,570			
24	06LPAY0300 - OTHER-LATEFEE		876			
25						
26	IDAHO					
27	07LPAY0300 - RES-LATEFEE		219,668			
28	07LPAY0300 - COM-LATEFEE		27,909			
29	07LPAY0300 - IND-LATEFEE		82,723			
30	07LPAY0300 - OTHER-LATEFEE		4,584			
31						
32	OREGON					
33	01LPAY0300 - RES-LATEFEE		3,027,099			
34	01LPAY0300 - COM-LATEFEE		777,068			
35	01LPAY0300 - IND-LATEFEE		225,412			
36	01LPAY0300 - OTHER-LATEFEE		45,333			
37						
38	UTAH					
39	08LPAY0300 - RES-LATEFEE		2,368,447			
40	08LPAY0300 - COM-LATEFEE		664,395			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	08LPAY0300 - IND-LATEFEE		198,342			
2	08LPAY0300 - OTHER-LATEFEE		79,748			
3	OTHER		493			
4						
5	WASHINGTON					
6	02LPAY0300 - RES-LATEFEE		567,301			
7	02LPAY0300 - COM-LATEFEE		136,148			
8	02LPAY0300 - IND-LATEFEE		28,465			
9	02LPAY0300 - OTHER-LATEFEE		2,355			
10						
11	WYOMING					
12	05LPAY0300 - RES-LATEFEE		461,390			
13	05LPAY0300 - COM-LATEFEE		118,729			
14	05LPAY0300 - IND-LATEFEE		71,962			
15	05LPAY0300 - OTHER-LATEFEE		-3,838			
16						
17	TOTAL FORFEITED DISCOUNTS		9,415,631			
18						
19	MISC SERVICE REVENUE					
20	CALIFORNIA					
21	06APSV0020 - AG PMP SRVC		1,820			
22	06CFR00003 - MTH MAINTENANC		1,454			
23	06CONN0300 - CA RECONNECTIO		33,165			
24	06FCBUYOUT		75,765			
25	06GNSV0025 - CA GEN SRVC		13,700			
26	06GNSV0A32 - GEN SRVC-20 KW		200			
27	06NEMAGG35 - CALIF NET METER		150			
28	06NETMT135 - CA RES NET		5,526			
29	06NML20135 - AGRI PUMP-NET		425			
30	06NMT20135 - AGRI PUMP-NET		560			
31	06NMT25135 - CA GEN SVC NET		465			
32	06NMT32135 - CA GEN SVC NET		25			
33	06NSMTR300 - NON-STND MTR		3,255			
34	06RCHK0300 - CA RET CHK CHR		11,904			
35	06RESD000D - RES SRVC		227,700			
36	06RESD00DN - CA RES SRVC -		23,120			
37	06RESD0DS8 - MULT FAM SBMET		200			
38	06RESDDL06 - CA LOW INCOME		121,408			
39	06RGNSV025 - CA SMALL		2,040			
40	06RNM25135 - CA NET MTR, GEN		35			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
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1	06TAMP0300 - CA TAMP & UNAU		750			
2	06TEMP0300 - CA TEMP SRVC C		1,700			
3	06XMTRTAMP - TAMP		462			
4	OTHER		-14,674			
5						
6	IDAHO					
7	07CFR00001 - MTH FAC SRVCHG		1,213			
8	07CONN0300 - ID RECONNECTIO		8,390			
9	07FCBUYOUT - FAC CHG BUYOUT		10,953			
10	07RCHK0300 - ID RET CHK CHR		35,920			
11	07TAMP0300		75			
12	07TEMP0014 - TEMP SRVC CONN		32,020			
13	OTHER		835			
14						
15	OREGON					
16	01ADMINFEE - SCH 272 ANN		18,561			
17	01APSV0041 - AG PMP SRVC BP		3,160			
18	01APSV041T - AGR PUMP		334			
19	01APSV041X - AG PMP SRVC		5,695			
20	01CFR00001 - MTH FACILITY S		99,124			
21	01CFR00003 - MTH MAINTENANC		17,817			
22	01CFR00004 - EMRGNCY ST&BY		25,609			
23	01CFR00005 - INTERMTNT SRVC		37,082			
24	01CFR00013 - MTH MISC CHRG		49,169			
25	01CGENAFOR - CUST GEN APP		13,439			
26	01CONN0300 - RECONNECTION		282,262			
27	01CONTSERV - OR 3RD PARTY		31,433			
28	01ESSC0600 - ESS CHG		1,738			
29	01FCBUYOUT - FAC CHG BUYOUT		172,869			
30	01GNSB0023 - OR GEN SRV, BPA,		13,641			
31	01GNSV0023 - OR GEN SRV, < 30		107,325			
32	01GNSV0028 - OR GEN SRV > 30		8,334			
33	01GNSV023T - OR GEN SRV, TOU		118			
34	01LGSV0030 - OR LRG GEN SRV, >		334			
35	01NETMT135 - NET METERING		37,092			
36	01NMT23135 - OR NET MTR, GEN,		2,692			
37	01NMT28135 - OR NET MTR, GEN,		406			
38	01NMTOU135 - TOU NET		334			
39	01NSMTR300 - OR STD METER		50,700			
40	01RCHK0300 - RET CHECK		320,420			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
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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	01RESD0004 - RES SRVC		1,973,949			
2	01RESD004T - RES TIME OPT		4,856			
3	01RGNSB023 - SMALL GEN		70,418			
4	01RGNSB028 - GENERAL SVC > 30		334			
5	01RNETM023 - NET METER RES		1,480			
6	01TAMP0300 - TAMP & UNAUTH		5,025			
7	01XTRN0011 - SALE ORDERS		2			
8	01TEMP0300 - TEMP SRVC CHRG		156,060			
9	01USBRON41 - KLAMATH BASIN		956			
10	01VIR04136 - OR RES VOL		2,040			
11	01XMTRTAMP - TAMP - UNAUTH		918			
12	OTHER		-73,559			
13						
14	UTAH					
15	08CFR00051 - MTH FAC SRVCHG		84,037			
16	08CFR00052 - ANN FAC SVCCHG		424			
17	08CFR00053 - MTHLY MAINTFEE		11,760			
18	08CFR00054 - NRES EMERGENCY		4,976			
19	08CFR00063 - MTH MISC CHARG		2,343			
20	08CFR00064 - ANN MISC CHARG		6,660			
21	08CGENFEEN - NRES CSTMR GEN		29,101			
22	08CGENFEER - RES CSTMR GEN		381,889			
23	08CGM23136 - UT NET METER SM		4			
24	08CONN0300 -		158,380			
25	08CONTSERV - 3RD PARTY O/S		93,000			
26	08FCBUYOUT - FAC CHG BUYOUT		605,036			
27	08NCON0300 - UT FEE NRES RE		3,175			
28	08NETMT135 - NET METERING		264			
29	08NSMTR300 - UT NON		849			
30	08RCHK0300 - UT RET CHK CHR		561,400			
31	08RCON0001 - CONNECT FEE		1,799,720			
32	08RESD0001 - RES SRVC		5,226			
33	08SOLRXFEE - SUBSCRI SOLAR		13,800			
34	08SSLR0001 - RES SUBSCRB		264			
35	08TAMP0300 - TAMP&UNAU		3,150			
36	08TEMP0014 - TEMP SRVC CONN		632,104			
37	08XMTRTAMP - TAMP - UNAUTH		69			
38	08VISIT300 - UT VISIT SRV CALL		19,985			
39	ENERGY FINANSWER NEW COM		675			
40	OTHER		-108,031			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	WASHINGTON					
2	02CFR00003 - MTH MAINTENANC		1,320			
3	02CFR00004 - EMRGNCY ST&BY		5,892			
4	02CFR00005 - INTERMTNT SRVC		4,281			
5	02CGENAFWA - CUSTOMER GEN		100			
6	02CGENAMWA - CUSTOMER GEN		29,195			
7	02CONN0300 - WA RECONNECTIO		40,020			
8	02FCBUYOUT - FAC CHG BUYOUT		31,072			
9	02NSMTR300 - WA STD METER		240			
10	02RCHK0300 - WA RET CHK CHR		64,340			
11	02RESD0016 - WA RES SRVC		762			
12	02TAMP0300 - WA TAMP & UNAU		1,500			
13	02TEMP0300 - WA TEMP SRVC C		26,245			
14	02XMTRTAMP - TAMP - UNAUTH		2,304			
15	OTHER		-7,707			
16						
17	WYOMING					
18	05CFR00003 - MTH MAINTENANC		1,768			
19	05CFR00004 - EMRGNCY ST&BY		18,134			
20	05CFR00005 - INTERMTNT SRVC		9,922			
21	05CFR00013 - MTH MISC CHRG		3,186			
22	05CONN0300 - WY RECONNECTIO		57,857			
23	05FCBUYOUT - FAC CHG BUYOUT		45,856			
24	05RCHK0300 - WY RET CHK CHR		85,950			
25	05RESD0002 - WY RES SRVC		1,008			
26	05TAMP0300		975			
27	05TEMP0300 - WY TEMP SRVC C		39,950			
28	05XMTRTAMP - TAMP - UNAUTH		54			
29	09CFR00005 - INTERMTNT SRVC		339			
30	OTHER		332			
31	05CONN0300 - WY RECONNECTIO		6,974			
32	05FCBUYOUT - FAC CHG BUYOUT		6,347			
33	05RCHK0300 - WY RET CHK CHR		9,420			
34	05TAMP0300		75			
35	05XMTRTAMP - TAMP - UNAUTH		35			
36	09CFR00001 - MTH FAC SRVCHG		5,067			
37	09CFR00014 - YR MISC CHRG		3			
38						
39	TOTAL MISC SERVICE REVENUE		8,845,804			
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	SALES OF WATER & WATER PWR					
2	UTAH					
3	WATER & WATER PWR SALES		53,658			
4						
5	TOTAL SALES OF WATER &		53,658			
6						
7	RENT FROM ELEC PROPERTIES					
8	CALIFORNIA					
9	06CFR00006 - MTH RNTAL CHRG		1,710			
10	RENT REVENUE - HYDRO		1,250			
11	RENT REVENUE - SUBLEASES		4,800			
12	JOINT USE		572,863			
13						
14	IDAHO					
15	07CFR00009 - YR LSE CHRG-EQ		782			
16	07INVCHG00 - INVEST MNT CHG		149			
17	07POLE0075 - STEEL POLES US		266			
18	RENT REVENUE - HYDRO		62,260			
19	RENT REVENUE- TRANSMISSION		250			
20	RENT REVENUE - SUBLEASES		1,662			
21	JOINT USE		184,580			
22						
23	OREGON					
24	01CFR00006 - MTH RNTAL CHRG		853,418			
25	RENTS - COMMON		1,247,005			
26	RENT REVENUE - DISTRIBUTION		3,108			
27	RENT REVENUE - GENERAL		65,035			
28	RENT REVENUE - HYDRO		2,450			
29	RENT REVENUE - SUBLEASES		3,390			
30	RENT REVENUE - TRANSMISSION		291,549			
31	MCI FOGWIRE REVENUE		3,351,249			
32	JOINT USE		3,119,392			
33						
34	UTAH					
35	08CFR00056 - MTH EQUIP RENT		33			
36	08CFR00058 - MTH EQUIP LEAS		518,752			
37	08INVCHG0N - INVEST MNT CHG		3,596			
38	08INVCHG0R - INVEST MNT CHG		216			
39	08POLE0075 - STEEL POLES US		51,405			
40	RENTS - COMMON		1,000,019			
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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1	RENTS - NON-COMMON		-1,500			
2	RENT REVENUE - CORPORATE		8,464			
3	RENT REVENUE - DISTRIBUTION		455,611			
4	RENT REVENUE - GENERAL		-2,862			
5	RENT REVENUE - HYDRO		39,394			
6	RENT REVENUE - STEAM		112,400			
7	RENT REVENUE - SUBLEASES		619,413			
8	RENT REVENUE - TRANSMISSION		911,876			
9	JOINT USE		2,230,776			
10						
11	WASHINGTON					
12	02CFR00001 - MTH FACILITY S		2,114			
13	02CFR00006 - MTH RNTAL CHRG		8,869			
14	RENTS - COMMON		282,337			
15	RENT REVENUE - GENERAL		2,866			
16	RENT REVENUE - HYDRO		97,189			
17	RENT REVENUE - TRANSMISSION		5,911			
18	JOINT USE		740,154			
19						
20	WYOMING					
21	05CFR00001 - MTH FACILITY S		11,524			
22	05CFR00006 - MTH RNTAL CHRG		2,482			
23	RENT REVENUE - DISTRIBUTION		9,000			
24	RENT REVENUE - GENERAL		66,217			
25	RENT REVENUE - STEAM		45,103			
26	RENT REVENUE - SUBLEASES		43,399			
27	JOINT USE		383,059			
28	09POLE0075 - STEEL POLES US		18,313			
29	RENT REVENUE - STEAM		26,430			
30						
31	TOTAL RENT FROM ELEC		17,459,728			
32						
33	OTHER ELECTRIC REVENUE					
34	M&S INVENTORY REVENUE		4,613,077			
35	MISC OTHER REVENUE		34,984			
36	NON-WHEELING SYSTEM REV		609,086			
37	RENEWABLE ENERGY CREDITS		2,878,143			
38	WIND BASED ANCILLARY SVC		9,193,455			
39						
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
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1	CALIFORNIA					
2	3RD PARTY TRANS O&M		28,701			
3	CA GHG ALLOW REV AMORT		12,254,503			
4	FISH, WILDLIFE, RECR		9,261			
5						
6	OREGON					
7	3RD PARTY TRANS O&M		160,036			
8	EIM REVENUE		14,860			
9	FERC TRANSMISSION REFUND		-3,135,370			
10	MISC OTHER REVENUE		760,660			
11						
12	UTAH					
13	3RD PARTY TRANS O&M		211,034			
14	ELEC INCOME - OTHER		54,509			
15	FISH, WILDLIFE, RECR		2,820			
16	FLYASH SALES		1,561,903			
17						
18	WASHINGTON					
19	TIMBER SALES - UTILITY		649,985			
20	WASH COLSTRIP 3		-52,188			
21						
22	WYOMING					
23	3RD PARTY TRANS O&M		71,978			
24	FLYASH SALES		2,514,061			
25	WY REG RECOVERY FEE		150,187			
26						
27	TOTAL OTHER ELEC REVENUE		32,585,685			
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	55,326,663	4,750,248,615	1,932,532	28,629	0.0859
42	Total Unbilled Rev.(See Instr. 6)	15,944	15,667,000	0	0	0.9826
43	TOTAL	55,342,607	4,765,915,615	1,932,532	28,637	0.0861

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SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	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	32
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	Avangrid Renewables, LLC	SF	T-12	NA	NA	NA
13	Avangrid Renewables, LLC	SF	T-13	NA	NA	NA
14	Avista Corporation	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
6,265	118,889	110,701		229,590	2
3,698	69,536	65,338		134,874	3
283,052	5,540,429	9,175,358	-1,065,485	13,650,302	4
897	16,263	15,624		31,887	5
9,319	143,458	162,332		305,790	6
-631			-122,000	-122,000	7
					8
					9
72,467		1,958,485		1,958,485	10
9,532		343,785		343,785	11
521,800		16,488,799		16,488,799	12
73			2,136	2,136	13
49,805		1,678,045		1,678,045	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Avista Corporation	SF	T-13	NA	NA	NA
2	Barclays Bank PLC	SF	T-12	NA	NA	NA
3	Basin Electric Power Cooperative, Inc.	SF	T-12	NA	NA	NA
4	Black Hills Power, Inc.	LF	441	50	50	48
5	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
6	Bonneville Power Administration	AD	T-12	NA	NA	NA
7	Bonneville Power Administration	LU	T-12	NA	NA	NA
8	Bonneville Power Administration	SF	T-12	NA	NA	NA
9	Bonneville Power Administration	SF	T-13	NA	NA	NA
10	Bonneville Power Administration	SF	WSPP-Q	NA	NA	NA
11	BP Energy Company	AD	T-12	NA	NA	NA
12	BP Energy Company	SF	T-12	NA	NA	NA
13	British Columbia Hydro and Power	SF	T-13	NA	NA	NA
14	Brookfield Energy Marketing LP	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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.
35			990	990	1
					2
6,453		179,408		179,408	3
310,745	995,663	6,452,663		7,448,326	4
39,740		969,173		969,173	5
			-14,010	-14,010	6
19,498		1,304,026	4,045,261	5,349,287	7
197,283		6,658,554		6,658,554	8
95			3,290	3,290	9
23,735		614,877		614,877	10
1,843			80,348	80,348	11
253,031		6,791,967		6,791,967	12
12			430	430	13
825		23,800		23,800	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	California Independent System Operator	SF	T-12	NA	NA	NA
2	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
3	Citigroup Energy, Inc.	SF	T-12	NA	NA	NA
4	City of Anaheim	SF	T-12	NA	NA	NA
5	City of Burbank	SF	T-12	NA	NA	NA
6	City of Glendale	SF	T-12	NA	NA	NA
7	City of Hurricane	IF	560	NA	NA	NA
8	City of Redding	SF	T-12	NA	NA	NA
9	City of Roseville	SF	T-12	NA	NA	NA
10	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
11	ConocoPhillips Company	SF	T-12	NA	NA	NA
12	Direct Energy Business Marketing, LLC	SF	T-12	NA	NA	NA
13	DTE Energy Trading, Inc.	SF	T-12	NA	NA	NA
14	EDF Trading North America, LLC	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	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
3,311		131,343		131,343	1
47,040		1,305,615		1,305,615	2
1,232,262		38,175,396		38,175,396	3
24		216		216	4
13,536		408,160		408,160	5
1,400		38,800		38,800	6
112		5,658		5,658	7
1,480		52,600		52,600	8
9,689		323,221		323,221	9
8,253		324,459		324,459	10
131,005		3,142,181		3,142,181	11
94,678		2,747,592		2,747,592	12
554,806		16,906,912		16,906,912	13
304			22,293	22,293	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

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	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
2	EDF Trading North America, LLC	SF	WSPP-Q	NA	NA	NA
3	El Paso Electric Company	SF	T-12	NA	NA	NA
4	Energy Keepers, Inc.	SF	T-12	NA	NA	NA
5	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
6	Exelon Generation Company, LLC	AD	T-12	NA	NA	NA
7	Exelon Generation Company, LLC	SF	T-12	NA	NA	NA
8	Exelon Generation Company, LLC	SF	WSPP-Q	NA	NA	NA
9	Gridforce Energy Management, LLC	SF	T-13	NA	NA	NA
10	Idaho Power Company	SF	T-12	NA	NA	NA
11	Idaho Power Company	SF	T-13	NA	NA	NA
12	Idaho Power Company	SF	WSPP-Q	NA	NA	NA
13	Imperial Irrigation District	SF	T-12	NA	NA	NA
14	Los Angeles Dept. of Water and Power	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 2019/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.
495,888		15,176,662		15,176,662	1
160		4,682		4,682	2
4,295		163,294		163,294	3
50		2,800		2,800	4
26,606		898,596		898,596	5
25			550	550	6
701,884		21,553,284		21,553,284	7
2,984		81,916		81,916	8
569			18,919	18,919	9
2,400		59,404		59,404	10
100			3,207	3,207	11
6,200		141,000		141,000	12
308		12,967		12,967	13
6,200		153,800		153,800	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Macquarie Energy LLC	AD	T-12	NA	NA	NA
2	Macquarie Energy LLC	SF	T-12	NA	NA	NA
3	Macquarie Energy LLC	SF	WSPP-Q	NA	NA	NA
4	Modesto Irrigation District	SF	T-12	NA	NA	NA
5	Morgan Stanley Capital Group, Inc.	AD	T-12	NA	NA	NA
6	Morgan Stanley Capital Group, Inc.	SF	T-12	NA	NA	NA
7	Morgan Stanley Capital Group, Inc.	SF	WSPP-Q	NA	NA	NA
8	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
9	NaturEner Power Watch, LLC	AD	T-13	NA	NA	NA
10	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
11	Nevada Power Company	SF	WSPP-Q	NA	NA	NA
12	NextEra Energy Marketing, LLC	SF	T-12	NA	NA	NA
13	NorthWestern Corporation	SF	T-12	NA	NA	NA
14	NorthWestern Corporation	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			1,267	1,267	1
91,606		2,768,437		2,768,437	2
13,160		360,436		360,436	3
30,544		1,118,561		1,118,561	4
1,075			47,299	47,299	5
1,710,940		44,719,442		44,719,442	6
9,665		275,179		275,179	7
1,984		60,157		60,157	8
			-34	-34	9
173			5,028	5,028	10
6,939		258,607		258,607	11
4,800		113,600		113,600	12
25		600		600	13
102			3,236	3,236	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

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 2019/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	NorthWestern Corporation	SF	WSPP-Q	NA	NA	NA
2	Portland General Electric Company	SF	T-12	NA	NA	NA
3	Portland General Electric Company	SF	T-13	NA	NA	NA
4	Portland General Electric Company	SF	WSPP-Q	NA	NA	NA
5	Powerex Corporation	SF	T-12	NA	NA	NA
6	Public Service Company of Colorado	AD	T-12	NA	NA	NA
7	Public Service Company of Colorado	SF	T-12	NA	NA	NA
8	Public Service Company of Colorado	SF	T-13	NA	NA	NA
9	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
10	PUD No. 1 of Chelan County	SF	T-12	NA	NA	NA
11	PUD No. 1 of Chelan County	SF	T-13	NA	NA	NA
12	PUD No. 1 of Douglas County	SF	T-12	NA	NA	NA
13	PUD No. 1 of Douglas County	SF	T-13	NA	NA	NA
14	PUD No. 1 of Snohomish County	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
12,556		455,047		455,047	1
42,083		1,498,409		1,498,409	2
140			4,758	4,758	3
1,600		82,000		82,000	4
209,377		5,775,666		5,775,666	5
-35			-1,367	-1,367	6
3,830,356		105,474,480		105,474,480	7
68			2,536	2,536	8
60,019		2,198,741		2,198,741	9
2,000		51,340		51,340	10
11			321	321	11
2,600		147,950		147,950	12
4			12	12	13
3,100		84,655		84,655	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	PUD No. 2 of Grant County	SF	T-13	NA	NA	NA
2	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
3	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
4	Rainbow Energy Marketing Corporation	SF	T-12	NA	NA	NA
5	Rainbow Energy Marketing Corporation	SF	WSPP-Q	NA	NA	NA
6	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
7	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
8	Salt River Project	SF	T-12	NA	NA	NA
9	Seattle City Light	SF	T-12	NA	NA	NA
10	Seattle City Light	SF	T-13	NA	NA	NA
11	Sempra Gas & Power Marketing, LIC	AD	T-12	NA	NA	NA
12	Sempra Gas & Power Marketing, LIC	SF	T-12	NA	NA	NA
13	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
14	Shell Energy North America (US), L.P.	SF	WSPP-Q	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 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4			40	40	1
47,406		1,695,388		1,695,388	2
33			1,123	1,123	3
5,122		244,919		244,919	4
1,200		24,000		24,000	5
5,229		188,270		188,270	6
32			1,091	1,091	7
9,190		425,151		425,151	8
14,645		560,971		560,971	9
3			54	54	10
1,934			55,520	55,520	11
344,140		8,550,435		8,550,435	12
574,795		20,847,120	-985	20,846,135	13
51,591		1,465,960		1,465,960	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
2	Southern California Edison Company	SF	T-12	NA	NA	NA
3	Tacoma Power	SF	T-12	NA	NA	NA
4	Tacoma Power	SF	T-13	NA	NA	NA
5	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
6	Tenaska Power Services Co.	SF	WSPP-Q	NA	NA	NA
7	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
8	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
9	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
10	Tri-State Gen. and Trans. Assoc.	SF	T-12	NA	NA	NA
11	Tucson Electric Power Company	SF	T-12	NA	NA	NA
12	Turlock Irrigation District	SF	T-12	NA	NA	NA
13	UNS Electric, Inc.	SF	T-12	NA	NA	NA
14	Utah Associated Municipal Power Systems	SF	WSPP-Q	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
102			3,327	3,327	1
95,880		2,769,846		2,769,846	2
21,275		666,238		666,238	3
7			265	265	4
70,402		2,559,233		2,559,233	5
82,194		2,166,244		2,166,244	6
58,069		2,334,820		2,334,820	7
187,854		5,852,472		5,852,472	8
1,200		56,700		56,700	9
5,404		141,374		141,374	10
164,894		6,676,710		6,676,710	11
262,060		8,116,256		8,116,256	12
35,480		1,343,739		1,343,739	13
15,469		471,547		471,547	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

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 2019/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	Vitol Inc.	SF	T-12	NA	NA	NA
2	Westar Energy, Inc.	SF	T-12	NA	NA	NA
3	Western Area Power Adm CO MO	SF	T-12	NA	NA	NA
4	Western Area Power Adm CO MO	SF	T-13	NA	NA	NA
5	Western Area Power Adm Lower CO	SF	T-12	NA	NA	NA
6	Western Area Power Adm Sierra Nevada	SF	T-12	NA	NA	NA
7	Western Area Power Adm Upper CO	SF	T-12	NA	NA	NA
8	Western Area Power Adm Great Plains	SF	T-13	NA	NA	NA
9	Transmission Loss Sales Revenue	AD	T-11	NA	NA	NA
10	Transmission Loss Sales Revenue	OS	T-11	NA	NA	NA
11	Test Generation		NA	NA	NA	NA
12	Netting - Bookouts		NA	NA	NA	NA
13	Netting - Trading		NA	NA	NA	NA
14	Accrual		NA	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 2019/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.
6,600		169,210		169,210	1
2,000		53,792		53,792	2
60,751		2,118,921		2,118,921	3
132			3,207	3,207	4
3,640		130,160		130,160	5
3,800		110,850		110,850	6
173,518		6,214,111		6,214,111	7
3			66	66	8
			-132,904	-132,904	9
199,203			6,755,864	6,755,864	10
-251,009			-4,906,847	-4,906,847	11
-8,044,824			-212,766,314	-212,766,314	12
			-3,167,676	-3,167,676	13
80,167			301,366	301,366	14
302,600	5,888,575	9,529,353	-1,187,485	14,230,443	
5,177,028	995,663	386,671,884	-209,626,333	178,041,214	
5,479,628	**6,884,238**	**396,201,237**	**-210,813,818**	**192,271,657**	

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

```
$  (796,534) Load retention
     (6,355) Settlement adjustment
   (262,596) Customer service charges related to:
               - Schedule  94, Utah Energy Balancing Account
               - Schedule  98, Utah Renewable Energy Credits Revenue Adjustment
               - Schedule 196, Utah Sustainable Transportation and Energy Plan Cost
                               Adjustment Pilot Program
____________   - Schedule 197, Utah Federal Tax Act Adjustment
$(1,065,485)
```

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.: 13 Column: j

Reserve share.

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

Reserve share.

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

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

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

Settlement adjustment.

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

Service Agreement 37

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

Settlement adjustment.

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

Service Agreement 37

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

Termination payment for Foote Creek.

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

Reserve share.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 310.1 Line No.: 13 Column: a
Complete name is British Columbia Hydro and Power Authority.

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

Schedule Page: 310.2 Line No.: 1 Column: a
Complete name is California Independent System Operator Corporation.

Schedule Page: 310.2 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 310.2 Line No.: 14 Column: j
Settlement adjustment.

Schedule Page: 310.3 Line No.: 6 Column: b
Settlement adjustment.

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

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

Schedule Page: 310.3 Line No.: 11 Column: j
Reserve share.

Schedule Page: 310.3 Line No.: 14 Column: a
Complete name is Los Angeles Department of Water and Power.

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

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

Schedule Page: 310.4 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 310.4 Line No.: 5 Column: j
Settlement adjustment.

Schedule Page: 310.4 Line No.: 9 Column: b
Settlement adjustment.

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

Schedule Page: 310.4 Line No.: 10 Column: j
Reserve share.

Schedule Page: 310.4 Line No.: 11 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: 310.4 Line No.: 14 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 3 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 310.5 Line No.: 6 Column: j
Settlement adjustment.

Schedule Page: 310.5 Line No.: 8 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 10 Column: a
This footnote applies to all occurrences of "PUD No. 1 of Chelan County" on pages 310-311. Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 310.5 Line No.: 11 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 12 Column: a
This footnote applies to all occurrences of "PUD No. 1 of Douglas County" on pages 310-311. Complete name is Public Utility District No. 1 of Douglas County.

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

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

Schedule Page: 310.6 Line No.: 1 Column: a
Complete name is Public Utility District No. 2 of Grant County.

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

Schedule Page: 310.6 Line No.: 3 Column: j
Reserve share.

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

Schedule Page: 310.6 Line No.: 10 Column: j
Reserve share.

Schedule Page: 310.6 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 310.6 Line No.: 11 Column: j
Settlement adjustment.

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

Schedule Page: 310.7 Line No.: 1 Column: a
Sierra Pacific Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 310.7 Line No.: 1 Column: j
Reserve share.

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

Schedule Page: 310.7 Line No.: 10 Column: a
Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 310.8 Line No.: 3 Column: a
This footnote applies to all occurrences of "Western Area Power Adm CO MO" on pages 310-311. Complete name is Western Area Power Administration - Colorado Missouri.

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

Schedule Page: 310.8 Line No.: 5 Column: a
Complete name is Western Area Power Administration - Lower Colorado.

Schedule Page: 310.8 Line No.: 6 Column: a
Complete name is Western Area Power Administration - Sierra Nevada.

Schedule Page: 310.8 Line No.: 7 Column: a
Complete name is Western Area Power Administration - Upper Colorado.

Schedule Page: 310.8 Line No.: 8 Column: a
Complete name is Western Area Power Administration - Upper Great Plains West.

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

Schedule Page: 310.8 Line No.: 9 Column: b
Settlement adjustment.

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

Schedule Page: 310.8 Line No.: 10 Column: b
Transmission loss sales revenues collected from PacifiCorp's third party transmission service customers.

Schedule Page: 310.8 Line No.: 10 Column: j
Transmission loss sales revenues collected from PacifiCorp's third party transmission service customers.

Schedule Page: 310.8 Line No.: 11 Column: j

The negative revenue reported on this line reflects test energy generated that was transferred to Account 107, Construction work in progress for the following wind-powered generating facilities: Glenrock; Glenrock III; Goodnoe Hills; High Plains; Leaning Juniper 1; Marengo; McFadden Ridge I; Rolling Hills; Seven Mile Hill; and Seven Mile Hill II.

Energy generated during testing was delivered to PacifiCorp's electric system for sale as accounted for under the guidance in 18 C.F.R., Part 101, Electric Plant Instructions Electric Plant Instructions 3, 18(a). Test energy is a component of construction work in progress and is reported at the fair value of the energy delivered.

Schedule Page: 310.8 Line No.: 12 Column: j

Reflects transactions that did not physically settle.

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

Reflects transactions that were categorized as trading activities.

Schedule Page: 310.8 Line No.: 14 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 2019/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	17,825,121	17,846,918
5	(501) Fuel	757,097,162	815,215,918
6	(502) Steam Expenses	80,249,325	80,653,310
7	(503) Steam from Other Sources	4,836,772	4,714,446
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,532,522	1,538,384
10	(506) Miscellaneous Steam Power Expenses	27,042,769	24,373,827
11	(507) Rents	492,466	488,625
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	889,076,137	944,831,428
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	7,293,482	7,987,432
16	(511) Maintenance of Structures	27,614,737	26,949,381
17	(512) Maintenance of Boiler Plant	89,039,742	94,244,196
18	(513) Maintenance of Electric Plant	39,509,020	40,477,428
19	(514) Maintenance of Miscellaneous Steam Plant	10,456,723	9,735,906
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	173,913,704	179,394,343
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,062,989,841	1,124,225,771
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	9,462,766	8,478,869
45	(536) Water for Power	36,194	38,379
46	(537) Hydraulic Expenses	4,073,308	4,538,642
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	18,007,655	17,012,228
49	(540) Rents	1,696,372	1,222,268
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	33,276,295	31,290,386
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	381	470
54	(542) Maintenance of Structures	646,717	717,063
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,770,311	1,426,368
56	(544) Maintenance of Electric Plant	2,013,122	1,683,128
57	(545) Maintenance of Miscellaneous Hydraulic Plant	4,378,310	3,880,263
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,808,841	7,707,292
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	42,085,136	38,997,678

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	355,808	285,602
63	(547) Fuel	280,208,082	239,131,815
64	(548) Generation Expenses	17,253,968	17,616,683
65	(549) Miscellaneous Other Power Generation Expenses	7,815,446	5,107,905
66	(550) Rents	3,234,050	4,360,755
67	TOTAL Operation (Enter Total of lines 62 thru 66)	308,867,354	266,502,760
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	2,374,413	4,396,956
71	(553) Maintenance of Generating and Electric Plant	12,239,103	17,759,259
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,982,747	3,138,006
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	17,596,263	25,294,221
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	326,463,617	291,796,981
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	633,195,384	667,434,104
77	(556) System Control and Load Dispatching	770,619	1,211,514
78	(557) Other Expenses	44,593,260	41,691,162
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	678,559,263	710,336,780
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,110,097,857	2,165,357,210
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,360,740	6,772,651
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,813,567	7,234,514
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,250,888	1,384,344
89	(561.5) Reliability, Planning and Standards Development	1,962,101	1,968,543
90	(561.6) Transmission Service Studies	82,323	102,948
91	(561.7) Generation Interconnection Studies	504,815	1,755,384
92	(561.8) Reliability, Planning and Standards Development Services	8,800,994	7,447,677
93	(562) Station Expenses	3,124,100	2,901,944
94	(563) Overhead Lines Expenses	1,089,585	864,557
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	145,825,268	135,021,597
97	(566) Miscellaneous Transmission Expenses	3,006,329	2,859,169
98	(567) Rents	2,244,063	2,138,345
99	TOTAL Operation (Enter Total of lines 83 thru 98)	183,064,773	170,451,673
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,304,375	1,444,581
102	(569) Maintenance of Structures	105,140	41,891
103	(569.1) Maintenance of Computer Hardware		67,060
104	(569.2) Maintenance of Computer Software	951,021	825,322
105	(569.3) Maintenance of Communication Equipment	4,732,027	5,238,837
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	11,796,851	11,984,857
108	(571) Maintenance of Overhead Lines	16,201,425	16,147,738
109	(572) Maintenance of Underground Lines	57,535	81,815
110	(573) Maintenance of Miscellaneous Transmission Plant	153,479	222,170
111	TOTAL Maintenance (Total of lines 101 thru 110)	35,301,853	36,054,271
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	218,366,626	206,505,944

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	9,520,507	8,848,063
135	(581) Load Dispatching	12,160,239	11,541,737
136	(582) Station Expenses	4,707,948	4,076,355
137	(583) Overhead Line Expenses	9,956,347	9,211,450
138	(584) Underground Line Expenses	621	2,063
139	(585) Street Lighting and Signal System Expenses	224,138	247,796
140	(586) Meter Expenses	2,526,289	2,790,673
141	(587) Customer Installations Expenses	15,268,629	14,205,310
142	(588) Miscellaneous Expenses	649,377	1,196,149
143	(589) Rents	2,874,305	3,182,216
144	TOTAL Operation (Enter Total of lines 134 thru 143)	57,888,400	55,301,812
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	6,381,190	5,835,359
147	(591) Maintenance of Structures	2,358,542	2,142,078
148	(592) Maintenance of Station Equipment	9,665,348	9,062,978
149	(593) Maintenance of Overhead Lines	88,649,749	89,351,304
150	(594) Maintenance of Underground Lines	27,326,536	24,670,628
151	(595) Maintenance of Line Transformers	1,003,084	974,547
152	(596) Maintenance of Street Lighting and Signal Systems	2,503,642	2,965,826
153	(597) Maintenance of Meters	529,287	225,334
154	(598) Maintenance of Miscellaneous Distribution Plant	6,497,561	6,728,870
155	TOTAL Maintenance (Total of lines 146 thru 154)	144,914,939	141,956,924
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	202,803,339	197,258,736
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,282,185	2,477,399
160	(902) Meter Reading Expenses	14,595,821	19,056,668
161	(903) Customer Records and Collection Expenses	46,565,556	50,336,486
162	(904) Uncollectible Accounts	13,068,251	11,655,692
163	(905) Miscellaneous Customer Accounts Expenses	347,870	135,391
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	76,859,683	83,661,636

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	6,737	117,633
168	(908) Customer Assistance Expenses	95,221,065	90,120,906
169	(909) Informational and Instructional Expenses	6,310,516	5,820,368
170	(910) Miscellaneous Customer Service and Informational Expenses	4,533	41,342
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	101,542,851	96,100,249
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	76,578,659	72,265,963
182	(921) Office Supplies and Expenses	9,594,354	9,971,031
183	(Less) (922) Administrative Expenses Transferred-Credit	34,578,091	31,909,798
184	(923) Outside Services Employed	22,040,045	19,890,624
185	(924) Property Insurance	14,929,761	12,338,561
186	(925) Injuries and Damages	8,096,669	16,740,134
187	(926) Employee Pensions and Benefits	102,224,372	113,736,594
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	25,605,836	22,484,361
190	(929) (Less) Duplicate Charges-Cr.	130,646,461	128,629,971
191	(930.1) General Advertising Expenses	55,028	580
192	(930.2) Miscellaneous General Expenses	2,244,072	2,225,689
193	(931) Rents	2,541,299	2,723,369
194	TOTAL Operation (Enter Total of lines 181 thru 193)	98,685,543	111,837,137
195	Maintenance		
196	(935) Maintenance of General Plant	24,451,060	23,525,832
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	123,136,603	135,362,969
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,832,806,959	2,884,246,744

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)	$ 14,929,761
Less: Situs property loss reserves, net of reimbursements(1)		10,192,677
Revised (924) Property Insurance		$ 4,737,084

(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, 2019, pension and postretirement regulatory asset amortization was $(2,684,722).

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)	$ 123,136,603
Less: Situs property loss reserves, net of reimbursements(1)		10,192,677
Less: Pension and postretirement regulatory asset amort. (2)		(2,684,722)
Revised TOTAL Administrative & General Expenses		$ 115,628,648

(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 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Power Purchases:					
2	Adams Solar Center LLC	AD		NA	NA	NA
3	Adams Solar Center LLC	LU		NA	NA	NA
4	Amor IX LLC	LU		NA	NA	NA
5	Apple, Inc.	LU		NA	NA	NA
6	Arizona Electric Power Cooperative	SF		NA	NA	NA
7	Arizona Electric Power Cooperative	AD		NA	NA	NA
8	Arizona Public Service Company	LF		NA	NA	NA
9	Arizona Public Service Company	SF		NA	NA	NA
10	Arizona Public Service Company	AD		NA	NA	NA
11	Avangrid Renewables, LLC	SF		NA	NA	NA
12	Avangrid Renewables, LLC	AD		NA	NA	NA
13	Avista Corporation	SF		NA	NA	NA
14	Ballard Hog Farms Inc.	LU		0	0	0
	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 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
					-1,987	-1,987	2
20,767				1,367,981	18,117	1,386,098	3
24,611				1,328,994	-15,000	1,313,994	4
5,193				409,072		409,072	5
30,353				1,102,286		1,102,286	6
					3,750	3,750	7
98,778				2,183,574		2,183,574	8
287,871				5,515,159		5,515,159	9
					-1,083	-1,083	10
785,902				33,602,095	1,167	33,603,262	11
1					104	104	12
138,294				5,284,535	6,724	5,291,259	13
228			5,070	12,145		17,215	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Barclays Bank PLC	AD		NA	NA	NA
2	Basin Electric Power Cooperative	SF		NA	NA	NA
3	BC Solar, LLC	LU		NA	NA	NA
4	Bear Creek Solar Center, LLC	LU		NA	NA	NA
5	Bear Creek Solar Center, LLC	LU		NA	NA	NA
6	Beaver City Corporation	LF		NA	NA	NA
7	Bell Mountain Hydro, LLC	LU		NA	NA	NA
8	Beryl Solar, LLC	LU		3	3	1
9	Big Top, LLC	LU		NA	NA	NA
10	Biomass One, L.P.	LU		NA	NA	NA
11	Birch Power Company, Inc.	LU		NA	NA	NA
12	Black Cap Solar, LLC	LU		NA	NA	NA
13	Black Hills Power, Inc.	SF		NA	NA	NA
14	Bly Solar Center, 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)	
					-5,696,981	-5,696,981	1
106,829				3,577,578		3,577,578	2
18,570				1,223,880		1,223,880	3
					19,785	19,785	4
22,665				1,492,873		1,492,873	5
27				2,801		2,801	6
806				71,601		71,601	7
5,641			416,812	300,113		716,925	8
3,276				254,626		254,626	9
162,616				12,594,337	2,809,629	15,403,966	10
13,011				833,996		833,996	11
678				21,825		21,825	12
10,084				426,207		426,207	13
					11,976	11,976	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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	Bly Solar Center, LLC	LU		NA	NA	NA
2	Bly Solar Center, LLC	AD		NA	NA	NA
3	Bonneville Power Administration	LF		NA	NA	NA
4	Bonneville Power Administration	SF		NA	NA	NA
5	Bourdet, Peter M	LU		NA	NA	NA
6	Box Canyon Limited Partnership	LU		3	4	2
7	BP Energy Company	SF		NA	NA	NA
8	BP Energy Company	AD		NA	NA	NA
9	Brigham Young University - Idaho	IU		NA	NA	NA
10	Brigham Young University - Idaho	AD		NA	NA	NA
11	Brookfield Energy Marketing LP	SF		NA	NA	NA
12	Brookfield Renewable Trading	SF		NA	NA	NA
13	Buckhorn Solar, LLC	LU		3	3	0
14	Butter Creek Power, LLC	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES 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.
18,040				1,188,171		1,188,171	1
20					836	836	2
					146,932	146,932	3
316,449				12,040,753	37,565	12,078,318	4
269				9,228		9,228	5
20,928			271,262	3,143,412		3,414,674	6
1,419,068				45,251,221		45,251,221	7
1,853					84,861	84,861	8
38,557				2,117,518		2,117,518	9
					-23,899	-23,899	10
54,200				2,810,720		2,810,720	11
49,625				1,651,022		1,651,022	12
5,030			431,159	267,580		698,739	13
11,294				872,869		872,869	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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 2019/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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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	C Drop Hydro, LLC	LU		NA	NA	NA
2	California Independent System Operator	SF		NA	NA	NA
3	Calpine Energy Services, L.P.	SF		NA	NA	NA
4	Cedar Valley Solar, LLC	LU		3	3	1
5	Cedar Valley Solar, LLC	AD		NA	NA	NA
6	Central Oregon Irrigation District	LU		3	4	3
7	Chiloquin Solar LLC	LU		NA	NA	NA
8	Chopin Wind, LLC	LU		NA	NA	NA
9	Citigroup Energy, Inc.	SF		NA	NA	NA
10	City of Albany	LU		NA	NA	NA
11	City of Anaheim	SF		NA	NA	NA
12	City of Astoria	LU		NA	NA	NA
13	City of Burbank	SF		NA	NA	NA
14	City of Hurricane	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,207				173,778		173,778	1
29,270				2,663,242		2,663,242	2
260,614				15,834,310		15,834,310	3
5,809			428,169	309,057		737,226	4
149					7,619	7,619	5
28,927			305,173	3,141,363		3,446,536	6
19,452				850,629		850,629	7
25,283				1,446,997		1,446,997	8
1,335,219				38,122,633		38,122,633	9
780				61,982		61,982	10
840				8,681		8,681	11
15				621		621	12
13,040				427,790		427,790	13
2,368				163,006		163,006	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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 2019/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 Idaho Falls	LU		NA	NA	NA
2	City of Pasadena	SF		NA	NA	NA
3	City of Portland, Water Bureau	LU		NA	NA	NA
4	City of Preston Idaho	LU		NA	NA	NA
5	City of Roseville	SF		NA	NA	NA
6	Clatskanie People's Utility District	SF		NA	NA	NA
7	Commercial Energy Management Inc.	LU		NA	NA	NA
8	Confederate Tribes of Warm Springs	LU		NA	NA	NA
9	ConocoPhillips Company	SF		NA	NA	NA
10	Consolidated Irrigation Company	LU		NA	NA	NA
11	Cottonwood Hydro, LLC	IU		NA	NA	NA
12	Crook County Solar 1, LLC	LU		NA	NA	NA
13	Deschutes Valley Water District	LU		5	4	3
14	Deseret Generation and Transmission	LF		100	100	88
	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.
48,730					1,744,932	1,744,932	1
161				3,927		3,927	2
166				13,131		13,131	3
2,633				162,071		162,071	4
6,548				1,270,674		1,270,674	5
769				18,486		18,486	6
2,221				126,903		126,903	7
312				10,178		10,178	8
585,885				18,558,664		18,558,664	9
2,085				124,862		124,862	10
3,327				160,345		160,345	11
1,096				36,238		36,238	12
28,184			513,536	3,959,903		4,473,439	13
541,968			18,175,560	12,558,772	4,679,760	35,414,092	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Direct Energy Business Marketing, LLC	SF		NA	NA	NA
2	Dorena Hydro, LLC	LU		NA	NA	NA
3	Douglas County, Inc.	LU		NA	NA	NA
4	Douglas County	LU		0	1	1
5	Draper Irrigation Company	IU		NA	NA	NA
6	Dry Creek LLC	LU		NA	NA	NA
7	Dry Creek LLC	AD		NA	NA	NA
8	DTE Energy Trading, Inc.	SF		NA	NA	NA
9	eBay Inc.	LU		NA	NA	NA
10	EDF Trading North America, LLC	SF		NA	NA	NA
11	EDF Trading North America, LLC	AD		NA	NA	NA
12	El Paso Electric Company	SF		NA	NA	NA
13	Elbe Solar Center, LLC	LU		NA	NA	NA
14	Elbe Solar Center, LLC	AD		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,654				525,998		525,998	1
10,754				848,230		848,230	2
995				22,632		22,632	3
4,470			98,739	648,091		746,830	4
731				52,146		52,146	5
10,376				623,246		623,246	6
-56					-3,560	-3,560	7
190,445				6,027,767		6,027,767	8
466				37,647		37,647	9
434,583				13,683,736		13,683,736	10
182					-166	-166	11
142,188				3,381,930		3,381,930	12
					18,448	18,448	13
					-457	-457	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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	Elbe Solar Center, LLC	LU		NA	NA	NA
2	Enterprise Solar, LLC	LU		NA	NA	NA
3	Enterprise Solar, LLC	LU		NA	NA	NA
4	Escalante Solar I, LLC	LU		NA	NA	NA
5	Escalante Solar II, LLC	LU		NA	NA	NA
6	Escalante Solar III, LLC	LU		NA	NA	NA
7	Eugene Water & Electric Board	SF		NA	NA	NA
8	Eurus Combine Hills I, LLC	LU		NA	NA	NA
9	Exelon Generation Company, LLC	SF		NA	NA	NA
10	Exelon Generation Company, LLC	AD		NA	NA	NA
11	ExxonMobil Production Company	LU		NA	NA	NA
12	Fall River Rural Electric Cooperative	LU		NA	NA	NA
13	Falls Creek H.P. Limited Partnership	LU		2	3	1
14	Farm Power Misty Meadow, 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 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.
20,745				1,363,154		1,363,154	1
					406,684	406,684	2
220,046				12,066,974		12,066,974	3
205,146				11,032,982		11,032,982	4
203,681				10,424,754		10,424,754	5
204,442				10,087,420		10,087,420	6
4,311				94,471		94,471	7
89,111				4,399,842		4,399,842	8
297,327				10,604,595		10,604,595	9
25					1,294	1,294	10
263				7,239		7,239	11
29,171				1,866,357		1,866,357	12
10,112			121,744	1,458,119		1,579,863	13
3,731				295,386		295,386	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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	Farmers Irrigation District	LU		NA	NA	NA
2	Fillmore City Corporation	LF		NA	NA	NA
3	Finley BioEnergy, LLC	LU		NA	NA	NA
4	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
5	Foote Creek II, LLC	LU		NA	NA	NA
6	Foote Creek III, LLC	LU		NA	NA	NA
7	Four Corners Windfarm, LLC	LU		NA	NA	NA
8	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
9	Georgetown Irrigation Company	LU		NA	NA	NA
10	Grand Valley Power	LF		NA	NA	NA
11	Granite Mountain Solar East, LLC	LU		NA	NA	NA
12	Granite Mountain Solar West, LLC	LU		NA	NA	NA
13	Granite Peak Solar, LLC	LU		3	3	0
14	Greenville Solar, LLC	LU		2	2	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)	
20,509				1,636,710		1,636,710	1
145				17,394		17,394	2
30,642				2,432,064		2,432,064	3
385				11,853		11,853	4
5,327				99,550		99,550	5
38,576				871,196		871,196	6
23,868				1,844,901		1,844,901	7
21,832				1,691,287		1,691,287	8
2,023				127,440		127,440	9
49				10,167		10,167	10
204,075				10,610,270		10,610,270	11
125,440				6,859,673		6,859,673	12
5,665			244,700	210,743		455,443	13
3,876			322,016	206,206		528,222	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Gridforce Energy Management, LLC	SF		NA	NA	NA
2	Guzman Renewable Energy Partners LLC	SF		NA	NA	NA
3	Hammerich 1 & 2	LU		NA	NA	NA
4	Harold Foster & Robert Walker	LU		NA	NA	NA
5	Hayward Paul Luckey and Joanne Luckey	LU		NA	NA	NA
6	Idaho Power Company	OS		NA	NA	NA
7	Idaho Power Company	SF		NA	NA	NA
8	Iron Springs Solar, LLC	LU		NA	NA	NA
9	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
10	Jake Amy	LU		NA	NA	NA
11	Joseph Community Solar, LLC	LU		NA	NA	NA
12	Keeton 1 & 2	LU		NA	NA	NA
13	Kettle Butte Digester LLC	LU		NA	NA	NA
14	Klamath Falls Solar 1, 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 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.
116					3,984	3,984	1
48				1,884		1,884	2
1,107				34,890		34,890	3
118				3,903		3,903	4
231				9,638		9,638	5
250				3,500		3,500	6
291,671				7,835,225	3,024	7,838,249	7
208,224				11,213,138		11,213,138	8
52				680		680	9
1,994				123,218		123,218	10
594				20,298		20,298	11
366				12,196		12,196	12
6,867				373,053		373,053	13
1,391				91,896		91,896	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Klamath Falls Solar 2, LLC	IU		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	Milford Flat Solar, LLC	LU		3	3	1
12	Mink Creek Hydro LLC	LU		NA	NA	NA
13	Monsanto Company	IU		NA	NA	NA
14	Morgan City Corporation	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	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 ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
6,564				286,559		286,559	1
4,367				179,060	46,461	225,521	2
6,210			245,680	231,018		476,698	3
165,577				10,035,710		10,035,710	4
98,713				5,158,135		5,158,135	5
286				6,515		6,515	6
259,354				11,716,954		11,716,954	7
7,671				492,471		492,471	8
333,988				26,175,615		26,175,615	9
22,695				1,683,048		1,683,048	10
6,079			245,253	226,133		471,386	11
10,281				642,176		642,176	12
					19,455,618	19,455,618	13
7				628		628	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
2	Morgan Stanley Capital Group, Inc.	AD		NA	NA	NA
3	Mountain Wind Power, LLC	LU		NA	NA	NA
4	Mountain Wind Power II, LLC	LU		NA	NA	NA
5	Myron Jones	LU		NA	NA	NA
6	NaturEner Power Watch, LLC	AD		NA	NA	NA
7	Nevada Power Company	SF		NA	NA	NA
8	NextEra Energy Marketing, LLC	SF		NA	NA	NA
9	Nichols Gap Limited Partnership	LU		1	0	0
10	NorthWestern Corporation	SF		NA	NA	NA
11	NorWest Energy 2, LLC	IU		NA	NA	NA
12	NorWest Energy 4, LLC	IU		NA	NA	NA
13	NorWest Energy 7, LLC	IU		NA	NA	NA
14	NorWest Energy 9, LLC	IU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
751,562				30,500,035		30,500,035	1
1,303					27,738	27,738	2
153,281				8,512,829		8,512,829	3
206,041				13,304,971		13,304,971	4
784				46,727		46,727	5
1					-34	-34	6
31,623				1,132,876		1,132,876	7
2,955				160,629		160,629	8
3,189			40,565	475,111		515,676	9
6,380				134,934	6,358	141,292	10
20,696				1,363,784		1,363,784	11
10,714				696,918		696,918	12
19,520				1,285,525		1,285,525	13
11,511				503,971		503,971	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	NorWest Energy 9, LLC	AD		NA	NA	NA
2	Nucor Corporation	IU		NA	NA	NA
3	Oak Lea Digester LLC	LU		NA	NA	NA
4	Oak Lea Digester LLC	AD		NA	NA	NA
5	Obsidian Finance Group, LLC	LU		NA	NA	NA
6	Old Mill Solar, LLC	LU		NA	NA	NA
7	OR Solar 3, LLC	LU		NA	NA	NA
8	OR Solar 5, LLC	LU		NA	NA	NA
9	OR Solar 6, LLC	LU		NA	NA	NA
10	OR Solar 8, LLC	LU		NA	NA	NA
11	Oregon Environmental Industries, LLC	LU		NA	NA	NA
12	Oregon Institute of Technology	LU		NA	NA	NA
13	Oregon Institute of Technology	AD		NA	NA	NA
14	Oregon Solar Incentive	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)	
192					5,069	5,069	1
					7,201,200	7,201,200	2
751				59,163		59,163	3
					50	50	4
930				30,082		30,082	5
11,163				837,215		837,215	6
24,887				1,087,550		1,087,550	7
19,565				854,819		854,819	8
24,451				1,068,963		1,068,963	9
24,677				1,076,978		1,076,978	10
13,989				1,035,162		1,035,162	11
174				9,890		9,890	12
					821	821	13
10,608				350,926		350,926	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
2	OSLH, LLC	IU		NA	NA	NA
3	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
4	Pavant Solar LLC	LU		NA	NA	NA
5	Pavant Solar II LLC	LU		NA	NA	NA
6	Pavant Solar III LLC	LU		NA	NA	NA
7	Pioneer Wind Park I, LLC	LU		NA	NA	NA
8	Platte River Power Authority	SF		NA	NA	NA
9	Portland General Electric Company	LF		NA	NA	NA
10	Portland General Electric Company	AD		NA	NA	NA
11	Portland General Electric Company	SF		NA	NA	NA
12	Power County Wind Park North, LLC	LU		NA	NA	NA
13	Power County Wind Park South, LLC	LU		NA	NA	NA
14	Powerex Corporation	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)	
21,184				1,635,833		1,635,833	1
21,654				945,939		945,939	2
16,444				1,276,839		1,276,839	3
110,950				4,487,103	166,425	4,653,528	4
115,089				3,510,009		3,510,009	5
48,133				2,541,438		2,541,438	6
282,578				11,278,486		11,278,486	7
19,629				100,885		100,885	8
12,241					104,129	104,129	9
					-89,325	-89,325	10
204,348				6,264,389	10,860	6,275,249	11
65,015				4,925,197		4,925,197	12
57,102				4,360,555		4,360,555	13
370,487				21,688,308		21,688,308	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Provo City Corporation	LF		NA	NA	NA
2	Public Service Company of Colorado	SF		NA	NA	NA
3	Public Service Company of Colorado	AD		NA	NA	NA
4	Public Service Company of New Mexico	SF		NA	NA	NA
5	Public Service Company of New Mexico	AD		NA	NA	NA
6	PUD No. 1 of Chelan County	SF		NA	NA	NA
7	PUD No. 1 of Douglas County	SF		NA	NA	NA
8	PUD No. 1 of Snohomish County	SF		NA	NA	NA
9	PUD No. 2 of Grant County	LU		NA	NA	NA
10	PUD No. 2 of Grant County	AD		NA	NA	NA
11	PUD No. 2 of Grant County	SF		NA	NA	NA
12	Puget Sound Energy, Inc.	SF		NA	NA	NA
13	Quichapa 1, LLC	LU		3	3	1
14	Quichapa 2, 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)	
46				4,122		4,122	1
1,890,453				56,828,092	2,933	56,831,025	2
87					4,749	4,749	3
77,945				2,434,433		2,434,433	4
-24					-1,409	-1,409	5
59,568				2,160,526	1,748	2,162,274	6
11,431				358,660	1,047	359,707	7
13,135				339,070		339,070	8
79,581					122,358	122,358	9
					272,989	272,989	10
98					3,181	3,181	11
102,727				3,288,448	11,518	3,299,966	12
7,956			244,369	295,980		540,349	13
7,899			243,543	293,838		537,381	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Quichapa 3, LLC	LU		3	3	1
2	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
3	Rock River I, LLC	LU		NA	NA	NA
4	Roseburg Forest Products Company	LU		NA	NA	NA
5	Roseburg LFG Energy, LLC	LU		NA	NA	NA
6	Sacramento Municipal Utility District	SF		NA	NA	NA
7	Sage Solar I LLC	LU		NA	NA	NA
8	Sage Solar II LLC	LU		NA	NA	NA
9	Sage Solar III LLC	LU		NA	NA	NA
10	Salt River Project	SF		NA	NA	NA
11	Salt River Project	AD		NA	NA	NA
12	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
13	Santiam Water Control District	LU		0	0	0
14	Seattle City Light	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)	
7,819			243,407	290,873		534,280	1
4,248				110,406		110,406	2
136,244				4,833,945		4,833,945	3
47,698				1,028,431		1,028,431	4
6,125				480,825		480,825	5
15,300				332,100		332,100	6
12,780				499,768		499,768	7
18,531				710,378		710,378	8
17,060				656,254		656,254	9
378,287				13,998,318		13,998,318	10
264					11,075	11,075	11
20,643				1,601,501		1,601,501	12
1,324			13,156	176,855		190,011	13
36,577				1,363,980	3,952	1,367,932	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Sempra Gas & Power Marketing, LLC	SF		NA	NA	NA
2	Sempra Gas & Power Marketing, LLC	AD		NA	NA	NA
3	Shell Energy North America (US), L.P.	SF		NA	NA	NA
4	Shiloh Warm Springs Ranch, LLC	LU		NA	NA	NA
5	Sierra Pacific Power Company	SF		NA	NA	NA
6	Simplot Phosphates, LLC	LU		NA	NA	NA
7	Solwatt, LLC	LU		NA	NA	NA
8	Southern California Edison Company	SF		NA	NA	NA
9	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
10	Sprague Hydro LLC	LU		0	0	0
11	St. Anthony Hydro, LLC	LU		NA	NA	NA
12	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
13	SunE DB18, LLC	LU		3	1	1
14	SunE DB24, 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)	
162,918				4,975,367		4,975,367	1
1,289					61,187	61,187	2
520,603				21,391,142		21,391,142	3
706				45,356		45,356	4
1,123				42,051	4,807	46,858	5
56				1,257		1,257	6
803				25,800		25,800	7
24				500		500	8
49,131				2,849,569		2,849,569	9
2,778			49,988	406,377		456,365	10
5,796				385,843		385,843	11
1,196				38,025		38,025	12
7,153			417,280	380,529		797,809	13
6,083			196,240	226,305		422,545	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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 2019/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	SunE Solar XVII Project 1, LLC	LU		3	8	4
2	SunE Solar XVII Project 2, LLC	LU		3	3	1
3	SunE Solar XVII Project 3, LLC	LU		3	2	1
4	Sunny Bar Ranch LP	LU		NA	NA	NA
5	Sunny Bar Ranch LP	AD		NA	NA	NA
6	Sunnyside Cogeneration Associates	LU		53	53	42
7	Swalley Irrigation District	LU		NA	NA	NA
8	Sweetwater Solar LLC	LU		NA	NA	NA
9	Sweetwater Solar LLC	AD		NA	NA	NA
10	Tacoma Power	SF		NA	NA	NA
11	Tata Chemicals (Soda Ash) Partners	LU		NA	NA	NA
12	Tenaska Power Services Co.	SF		NA	NA	NA
13	Tesoro Refining & Marketing Co LLC	LU		NA	NA	NA
14	Thayn 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)	
7,130			405,124	379,298		784,422	1
6,082			354,505	323,546		678,051	2
6,567			218,611	244,309		462,920	3
2,066				131,442		131,442	4
-812					-51,956	-51,956	5
401,228				29,537,917		29,537,917	6
2,154				171,078		171,078	7
181,501				7,816,242		7,816,242	8
					-6,138	-6,138	9
18,116				666,990	1,823	668,813	10
3,125				52,493		52,493	11
101,998				2,742,909		2,742,909	12
6,015				109,332		109,332	13
2,633				117,879		117,879	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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 2019/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	The Energy Authority, Inc.	SF		NA	NA	NA
2	Three Buttes Windpower, LLC	LU		NA	NA	NA
3	Three Peaks Power, LLC	LU		NA	NA	NA
4	Three Sisters Irrigation District	LU		NA	NA	NA
5	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
6	TMF Biofuels, LLC	LU		NA	NA	NA
7	Tooele Army Depot	LU		NA	NA	NA
8	Top of the World Wind Energy LLC	LU		NA	NA	NA
9	TransAlta Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
10	TransCanada Energy Sales Ltd.	SF		NA	NA	NA
11	Tri-State Generation and Transmission	LF		26	25	13
12	Tri-State Generation and Transmission	SF		NA	NA	NA
13	Tucson Electric Power Company	SF		NA	NA	NA
14	Tumbleweed 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)	
54,426				1,239,024		1,239,024	1
324,598				20,681,645		20,681,645	2
217,174				9,273,600		9,273,600	3
2,591				140,179		140,179	4
19,143				1,516,075		1,516,075	5
33,547				2,499,100		2,499,100	6
745				22,254		22,254	7
555,018				37,587,023	1,901,599	39,488,622	8
161,530				6,966,600		6,966,600	9
9,600				753,000		753,000	10
108,308			6,219,000	3,503,764		9,722,764	11
55,119				3,258,239		3,258,239	12
180,374				5,056,658		5,056,658	13
19,266				841,643		841,643	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Turlock Irrigation District	SF		NA	NA	NA
2	U.S. Dept of the Interior	LU		NA	NA	NA
3	U.S. Air Force at Hill Air Force Base	LU		NA	NA	NA
4	UNS Electric, Inc.	SF		NA	NA	NA
5	US Magnesium LLC	LU		NA	NA	NA
6	Utah Associated Municipal Power System	LF		NA	NA	NA
7	Utah Associated Municipal Power System	SF		NA	NA	NA
8	Utah Municipal Power Agency	SF		NA	NA	NA
9	Utah Red Hills Renewable Park, LLC	LU		NA	NA	NA
10	Utah Retail Solar Customers	LU		NA	NA	NA
11	Utah Retail Solar Customers	AD		NA	NA	NA
12	Vitol Inc.	SF		NA	NA	NA
13	Wagon Trail, LLC	LU		NA	NA	NA
14	Ward Butte Windfarm, LLC	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
43,758				2,670,752		2,670,752	1
32				2,158		2,158	2
8,908				507,182		507,182	3
16,499				487,405		487,405	4
					5,412,135	5,412,135	5
60,752				3,094,924		3,094,924	6
8				192		192	7
3,432				160,456		160,456	8
205,468				12,119,273		12,119,273	9
26,900				2,390,583		2,390,583	10
					-133	-133	11
17,600				515,188		515,188	12
6,379				494,950		494,950	13
14,604				1,127,493		1,127,493	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Weber County	LU		NA	NA	NA
2	Weber County	AD		NA	NA	NA
3	Westar Energy, Inc	SF		NA	NA	NA
4	Western Area Power Administration	LF		NA	NA	NA
5	Western Area Power Administration	SF		NA	NA	NA
6	Western Area Power Administration	AD		NA	NA	NA
7	Wolverine Creek Energy, LLC	LU		NA	NA	NA
8	Wolverine Creek Energy, LLC	AD		NA	NA	NA
9	Woodline Solar, LLC	IU		NA	NA	NA
10	Yakima-Tieton Irrigation District	LU		1	0	0
11	UT STEP Gadsby Curtailment					
12	CA Greenhouse Gas Allowance Purchases					
13	Net Power Cost Deferrals					
14	Netting - Bookouts					
	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)	
530				29,621		29,621	1
					-263	-263	2
2,800				224,620		224,620	3
7,871				333,364		333,364	4
24,001				665,432	1,672	667,104	5
					8,395	8,395	6
163,896				9,932,094		9,932,094	7
					3	3	8
18,705				816,176		816,176	9
5,437			63,250	146,066		209,316	10
				-7,067		-7,067	11
					4,420,402	4,420,402	12
					-52,470,478	-52,470,478	13
-8,044,855					-212,766,314	-212,766,314	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

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	Netting - Trading					
2	System Deviation					
3	Accrual					
4						
5	Power Exchanges:					
6	Arizona Public Service Company	EX	307	NA	NA	NA
7	Avista Corporation	EX	382	NA	NA	NA
8	Bonneville Power Administration	EX	237	NA	NA	NA
9	Bonneville Power Administration	AD	237	NA	NA	NA
10	Bonneville Power Administration	EX	519	NA	NA	NA
11	Bonneville Power Administration	EX	T-BPA	NA	NA	NA
12	Bonneville Power Administration	AD	T-BPA	NA	NA	NA
13	California Independent System Operator	EX	T-12	NA	NA	NA
14	California Independent System Operator	AD	T-12	NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/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)	
					-3,167,676	-3,167,676	1
838							2
					-13,688,948	-13,688,948	3
							4
							5
	570,517	566,506			5,149,751	5,149,751	6
		1,765					7
	12,507	404			39,204	39,204	8
					14,586	14,586	9
	71,999	72,746					10
	256,761	5,368			624,778	624,778	11
					7,255	7,255	12
	4,467,627	4,136,075			-48,264,721	-48,264,721	13
					59,479	59,479	14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	California Independent System Operator	EX	T-11	NA	NA	NA
2	California Independent System Operator	AD	T-11	NA	NA	NA
3	City of Roseville	AD	T-11	NA	NA	NA
4	Emerald People's Utility District	EX	351	NA	NA	NA
5	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
6	Idaho Power Company	EX	708	NA	NA	NA
7	Idaho Power Company	EX	T-6	NA	NA	NA
8	Los Angeles Dept. of Water and Power	EX	OV-1	NA	NA	NA
9	Los Angeles Dept. of Water and Power	AD	OV-1	NA	NA	NA
10	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
11	Milford Wind Corridor Phase I, LLC	AD	OV-1	NA	NA	NA
12	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
13	Milford Wind Corridor Phase II, LLC	AD	OV-1	NA	NA	NA
14	NorthWestern Corporation	EX	160	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)	
					5,654,152	5,654,152	1
					3,949,612	3,949,612	2
					164,072	164,072	3
		747			-18,664	-18,664	4
	9,732	10,037					5
	91,519	89,566					6
	2,064	2,036					7
	3,833				327,900	327,900	8
					29,643	29,643	9
		2,771			-191,630	-191,630	10
					-8,777	-8,777	11
		806			-140,406	-140,406	12
					1,940	1,940	13
	380						14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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.

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

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

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

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	Portland General Electric Company	EX	T-8	NA	NA	NA
2	Public Service Company of Colorado	EX	334	NA	NA	NA
3	PUD No. 1 of Cowlitz County	EX	442	NA	NA	NA
4	Seattle City Light	EX	554	NA	NA	NA
5	Western Area Power Administration	EX	LAS-4	NA	NA	NA
6	Western Area Power Administration	AD	LAS-4	NA	NA	NA
7	Imbalance Energy Accrual	EX	T-11	NA	NA	NA
8	Imbalance Energy Accrual	AD	T-11	NA	NA	NA
9						
10						
11						
12						
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.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	4,353						1
	1,314,000	1,313,207			5,400,000	5,400,000	2
	137,741	139,812					3
	303,461	338,452			-2,055,198	-2,055,198	4
	2,375	143,543			-567,750	-567,750	5
		3,000			-100,733	-100,733	6
	441,617				16,417,948	16,417,948	7
	17,309				-772,844	-772,844	8
							9
							10
							11
							12
							13
							14
12,097,791	7,707,795	6,826,841	30,533,911	855,648,190	-252,986,717	633,195,384	

Schedule Page: 326 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 2 Column: l
Settlement adjustment.

Schedule Page: 326 Line No.: 3 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326 Line No.: 4 Column: l
Liquidated damages.

Schedule Page: 326 Line No.: 6 Column: a
Complete name is Arizona Electric Power Cooperative, Inc.

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: b
Arizona Public Service Company - contract termination date: October 31, 2020.

Schedule Page: 326 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 10 Column: l
Settlement adjustment.

Schedule Page: 326 Line No.: 11 Column: l
Reserve share.

Schedule Page: 326 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 12 Column: l
Settlement adjustment.

Schedule Page: 326 Line No.: 13 Column: l
Reserve share.

Schedule Page: 326.1 Line No.: 1 Column: b
Litigation settlement adjustment.

Schedule Page: 326.1 Line No.: 1 Column: l
Litigation settlement adjustment.

Schedule Page: 326.1 Line No.: 4 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326.1 Line No.: 6 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.1 Line No.: 10 Column: l
Non-generation agreement.

Schedule Page: 326.1 Line No.: 12 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.: 14 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326.2 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326.2 Line No.: 2 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 3 Column: b
Bonneville Power Administration - contract termination date: Upon 30 days written notice.

Schedule Page: 326.2 Line No.: 3 Column: l
Ancillary services.

Schedule Page: 326.2 Line No.: 4 Column: l
Reserve share.

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

Schedule Page: 326.2 Line No.: 8 Column: l
Settlement adjustment.

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

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

Schedule Page: 326.2 Line No.: 12 Column: a
Complete name is Brookfield Renewable Trading and Marketing LP.

Schedule Page: 326.3 Line No.: 2 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: 326.3 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 326.3 Line No.: 5 Column: l
Settlement adjustment.

Schedule Page: 326.3 Line No.: 14 Column: b
City of Hurricane - contract termination date: August 31, 2022.

Schedule Page: 326.4 Line No.: 1 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.4 Line No.: 3 Column: a
Complete name is City of Portland, Portland Water Bureau.

Schedule Page: 326.4 Line No.: 14 Column: a
Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 326.4 Line No.: 14 Column: b
Deseret Generation and Transmission Co-operative - contract termination date: September 30, 2024.

Schedule Page: 326.4 Line No.: 14 Column: l
Reimbursement to counterparty for operation and maintenance costs at coal fired generating facility located in Vernal, Utah.

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

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

Schedule Page: 326.5 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.5 Line No.: 11 Column: l
Settlement adjustment.

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: b
Settlement adjustment.

Schedule Page: 326.5 Line No.: 14 Column: l
Settlement adjustment.

Schedule Page: 326.6 Line No.: 2 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

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

Schedule Page: 326.6 Line No.: 10 Column: l
Settlement adjustment.

Schedule Page: 326.6 Line No.: 12 Column: a
Complete name is Fall River Rural Electric Cooperative, Inc.

Schedule Page: 326.7 Line No.: 2 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.7 Line No.: 4 Column: b
Flathead Electric Cooperative, Inc. - contract termination date: September 30, 2021.

Schedule Page: 326.7 Line No.: 10 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 1 Column: l
Reserve share.

Schedule Page: 326.8 Line No.: 5 Column: a
Complete name is Hayward Paul Luckey and Joanne Luckey Revocable Trust of 2005.

Schedule Page: 326.8 Line No.: 6 Column: b
Secondary, economy, renewable attributes and/or non-firm.

Schedule Page: 326.8 Line No.: 7 Column: l
Reserve share.

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.: 13 Column: l
Compensation for interruptible service and operating reserves.

Schedule Page: 326.9 Line No.: 14 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.10 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 2 Column: l
Settlement adjustment.

Schedule Page: 326.10 Line No.: 5 Column: a
Complete name is Myron Jones, Nola Jones, Larry Oja and Christie Oja.

Schedule Page: 326.10 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 6 Column: l
Reserve share.

Schedule Page: 326.10 Line No.: 7 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: 326.10 Line No.: 10 Column: l
Reserve share.

Schedule Page: 326.11 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.11 Line No.: 1 Column: l
Settlement adjustment.

Schedule Page: 326.11 Line No.: 2 Column: b
Nucor Corporation - contract termination date: December 31, 2019.

Schedule Page: 326.11 Line No.: 2 Column: l
Ancillary services.

Schedule Page: 326.11 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 326.11 Line No.: 4 Column: l
Settlement adjustment.

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.: 4 Column: l
Purchase of renewable energy credit certificates for renewable portfolio standard requirements.

Schedule Page: 326.12 Line No.: 9 Column: b
Portland General Electric Company - contract termination date: When the Round Butte project no longer operates for power production purposes.

Schedule Page: 326.12 Line No.: 9 Column: l
Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.12 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.12 Line No.: 10 Column: l
Settlement adjustment.

Schedule Page: 326.12 Line No.: 11 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 1 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

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

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.: 5 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 5 Column: l
Settlement adjustment.

Schedule Page: 326.13 Line No.: 6 Column: a
Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 326.13 Line No.: 6 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 7 Column: a
Complete name is Public Utility District No. 1 of Douglas County.

Schedule Page: 326.13 Line No.: 7 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 8 Column: a
Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 326.13 Line No.: 9 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: 326.13 Line No.: 9 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.13 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.13 Line No.: 10 Column: l
Settlement adjustment.

Schedule Page: 326.13 Line No.: 11 Column: l
Reserve share.

Schedule Page: 326.13 Line No.: 12 Column: l
Reserve share.

Schedule Page: 326.14 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.14 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326.14 Line No.: 14 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.: 5 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.: 5 Column: l
Reserve share.

Schedule Page: 326.16 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 326.16 Line No.: 5 Column: l
Settlement adjustment.

Schedule Page: 326.16 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.16 Line No.: 9 Column: l
Settlement adjustment.

Schedule Page: 326.16 Line No.: 10 Column: l
Reserve share.

Schedule Page: 326.16 Line No.: 13 Column: a
Complete name is Tesoro Refining & Marketing Company LLC.

Schedule Page: 326.17 Line No.: 8 Column: l
Non-generation agreement.

Schedule Page: 326.17 Line No.: 11 Column: a
This footnote applies to all occurrences of "Tri-State Generation and Transmission" on pages 326-327. Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 326.17 Line No.: 11 Column: b
Tri-State Generation and Transmission Association, Inc. - contract termination date: December 31, 2020.

Schedule Page: 326.18 Line No.: 2 Column: a
Complete name is U.S. Department of the Interior - Bureau of Land Management.

Schedule Page: 326.18 Line No.: 5 Column: b
US Magnesium LLC - contract termination date: December 31, 2019.

Schedule Page: 326.18 Line No.: 5 Column: l
Ancillary services.

Schedule Page: 326.18 Line No.: 6 Column: b
Utah Associated Municipal Power System - contract termination date: March 31, 2022.

Schedule Page: 326.18 Line No.: 11 Column: b
Settlement adjustment.

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

Schedule Page: 326.19 Line No.: 2 Column: b
Settlement adjustment.

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

Schedule Page: 326.19 Line No.: 4 Column: b
Western Area Power Administration - contract termination date: May 31, 2022.

Schedule Page: 326.19 Line No.: 5 Column: l
Reserve share.

Schedule Page: 326.19 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 6 Column: l
Settlement adjustment.

Schedule Page: 326.19 Line No.: 8 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 8 Column: l
Settlement adjustment.

Schedule Page: 326.19 Line No.: 11 Column: a
Complete name is Utah Sustainable Transportation and Energy Plan, Gadsby plant curtailment.

Schedule Page: 326.19 Line No.: 12 Column: l
Purchases of greenhouse gas allowances for compliance with the California Air Resources Board greenhouse gas cap-and-trade program.

Schedule Page: 326.19 Line No.: 13 Column: l
Deferrals and associated amortization under various energy cost adjustment mechanisms.

Schedule Page: 326.19 Line No.: 14 Column: l
Reflects transactions that did not physically settle.

Schedule Page: 326.20 Line No.: 1 Column: l
Reflects transactions that were categorized as trading activities.

Schedule Page: 326.20 Line No.: 2 Column: g
Adjustment for inadvertent intercharge.

Schedule Page: 326.20 Line No.: 3 Column: l
Represents the difference between actual purchase expenses for the period as reflected on the individual line items within this schedule and the accruals charged to Account 555, Purchased power, during this period.

Schedule Page: 326.20 Line No.: 6 Column: l
Exchange energy charge/(credit).

Schedule Page: 326.20 Line No.: 8 Column: l
Storage and exchange charges.

Schedule Page: 326.20 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.20 Line No.: 9 Column: l
Settlement adjustment.

Schedule Page: 326.20 Line No.: 11 Column: l
Storage and exchange charges.

Schedule Page: 326.20 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.20 Line No.: 12 Column: l
Settlement adjustment.

Schedule Page: 326.20 Line No.: 13 Column: l
Energy Imbalance Market ("EIM") participating resource settlements in EIM.

Schedule Page: 326.20 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.20 Line No.: 14 Column: l
Settlement adjustment.

Schedule Page: 326.21 Line No.: 1 Column: l
Energy Imbalance Market ("EIM") entity settlements in EIM.

Schedule Page: 326.21 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326.21 Line No.: 2 Column: l
Settlement adjustment.

Schedule Page: 326.21 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.21 Line No.: 3 Column: l
Imbalance energy.

Schedule Page: 326.21 Line No.: 4 Column: l
Exchange energy charge/(credit).

Schedule Page: 326.21 Line No.: 8 Column: l
Station service for third-party wind project.

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: l
Reimbursement for providing station service to third-party wind project.

Schedule Page: 326.21 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.21 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326.21 Line No.: 12 Column: l
Reimbursement for providing station service to third-party wind project.

Schedule Page: 326.21 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.21 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.22 Line No.: 2 Column: l
Exchange energy charge/(credit).

Schedule Page: 326.22 Line No.: 3 Column: a
Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 326.22 Line No.: 4 Column: l
Exchange energy charge/(credit).

Schedule Page: 326.22 Line No.: 5 Column: l
Imbalance energy settlements between PacifiCorp, the transmission provider and third party transmission customers.

Schedule Page: 326.22 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.22 Line No.: 6 Column: l
Settlement adjustment.

Schedule Page: 326.22 Line No.: 7 Column: l
Imbalance energy settlements between PacifiCorp, the transmission provider and third party transmission customers.

Schedule Page: 326.22 Line No.: 8 Column: b
Settlement adjustment.

Schedule Page: 326.22 Line No.: 8 Column: l
Settlement adjustment.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	3 Phase Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
2	3 Phase Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	AD
3	Arizona Public Service Company	Arizona Public Service Company	various signatories	OS
4	Arizona Public Service Company	Arizona Public Service Company	various signatories	NF
5	Avangrid Renewables, LLC	various signatories	various signatories	NF
6	Avangrid Renewables, LLC	various signatories	various signatories	AD
7	Avangrid Renewables, LLC	various signatories	various signatories	SFP
8	Avangrid Renewables, LLC	various signatories	various signatories	AD
9	Avangrid Renewables, LLC	Avangrid Renewables, LLC	various signatories	OS
10	Avangrid Renewables, LLC	Avangrid Renewables, LLC	various signatories	AD
11	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
12	Avangrid Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
13	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
14	Avangrid Renewables, LLC	Avangrid Renewables, LLC	various signatories	AD
15	Avista Corporation	various signatories	various signatories	NF
16	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	FNO
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	NF
19	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
20	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	SFP
21	Basin Electric Power Cooperative, Inc.	Western Area Power Administration	Powder River Energy Corporation	AD
22	Black Hills/Colorado Electric Utility Company	various signatories	various signatories	NF
23	Black Hills/Colorado Electric Utility Company	various signatories	various signatories	SFP
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	various signatories	various signatories	NF
29	Black Hills Corporation	various signatories	various signatories	AD
30	Black Hills Corporation	various signatories	various signatories	SFP
31	Black Hills Corporation	various signatories	various signatories	AD
32	Black Hills Power Marketing	various signatories	various signatories	NF
33	Black Hills Power Marketing	various signatories	various signatories	AD
34	Black Hills Power Marketing	various signatories	various signatories	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)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
SA 876	Bonneville Power Adm	Various	1	577	577	1
SA 876	Bonneville Power Adm	Various		8	8	2
RS 436		Borah/Brady Sub				3
SA 42	Various	Various		672	672	4
SA 121	Various	Various		206,799	206,799	5
SA 121	Various	Various		16,603	16,603	6
SA 122	Various	Various		67,324	67,324	7
SA 122	Various	Various		3,218	3,218	8
SA 476						9
SA 476						10
SA 895	Trona Substation	Red Butte/Mona Sub	31	64,410	64,410	11
SA 895	Trona Substation	Red Butte/Mona Sub		6,407	6,407	12
SA 742	Ponderosa Substation	Various	32	251,535	251,535	13
SA 742	Ponderosa Substation	Various	31	22,862	22,862	14
SA 886	Various	Various		2,621	2,621	15
SA 505	Yellowtail Sub	Sheridan Substation	10	71,013	71,013	16
SA 505	Yellowtail Sub	Sheridan Substation	10	6,938	6,938	17
SA 607	Various	Various		46,761	46,761	18
SA 607	Various	Various		30,053	30,053	19
SA 606	Various	Various		13,835	13,835	20
SA 606	Various	Various				21
SA 563	Various	Various		692	692	22
SA 562	Various	Various		60	60	23
SA 347	Various	Sheridan Substation	47	269,606	269,606	24
SA 347	Various	Sheridan Substation	47	28,460	28,460	25
SA 67	Various	Wyodak Substation	52	118,362	118,362	26
SA 67	Various	Wyodak Substation	52			27
SA 768	Various	Various		13,782	13,782	28
SA 768	Various	Various				29
SA 767	Various	Various		5,460	5,460	30
SA 767	Various	Various				31
SA 43	Various	Various		1,969	1,969	32
SA 43	Various	Various				33
SA 714	Various	Various		192	192	34
			5,281	**15,241,847**	**15,129,193**	

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.
2,540		473	3,013	1
		339	339	2
				3
	2,632	107	2,739	4
	1,879,203	385,320	2,264,523	5
		185,594	185,594	6
	727,802	29,344	757,146	7
		44,259	44,259	8
		210,063	210,063	9
		20,437	20,437	10
845,473		123,158	968,631	11
		56,764	56,764	12
877,348		328,626	1,205,974	13
		834,762	834,762	14
	20,673	838	21,511	15
308,436		53,210	361,646	16
		18,071	18,071	17
	346,795	14,146	360,941	18
		215,937	215,937	19
	93,021	3,752	96,773	20
		2,038	2,038	21
	3,962	162	4,124	22
	575	23	598	23
1,374,745		55,622	1,430,367	24
		84,767	84,767	25
1,551,588		62,797	1,614,385	26
		94,606	94,606	27
	61,792	2,523	64,315	28
		24,345	24,345	29
	41,678	1,684	43,362	30
		659	659	31
	12,912	523	13,435	32
		108	108	33
	1,533	62	1,595	34
71,429,114	**16,491,269**	**23,992,613**	**111,912,996**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	various signatories	various signatories	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	various signatories	various signatories	NF
24	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
25	Bonneville Power Administration	various signatories	various signatories	FNO
26	Bonneville Power Administration	various signatories	various signatories	AD
27	Bonneville Power Administration	Bonneville Power Administration	PUD No. 1 of Clark County	FNO
28	Bonneville Power Administration	Bonneville Power Administration	PUD No. 1 of Clark County	AD
29	Brookfield Energy Marketing, Inc.	various signatories	various signatories	NF
30	Calpine Energy Solutions, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
31	Calpine Energy Solutions, LLC	Bonneville Power Administration	Oregon Direct Access	AD
32	City of Roseville	City of Roseville	City of Roseville	LFP
33	City of Roseville	City of Roseville	City of Roseville	AD
34	Clatskanie People's Utility District	Clatskanie People's Utility Dist	Clatskanie People's Utility Dist	LFP
	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 2019/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 714	Various	Various				1
RS 369	Midpoint Substation	Summer Lake Sub				2
RS 237	Various	Various	352	1,048,115	1,048,115	3
RS 237	Various	Various	300	101,667	101,667	4
SA 656	Lost Creek Hydro Plt	Alvey Substation	58	253,190	253,190	5
SA 656	Lost Creek Hydro Plt	Alvey Substation	58	14,017	14,017	6
SA 229	Bonneville Power Adm	Gazley Substation	3	24,203	24,203	7
SA 229	Bonneville Power Adm	Gazley Substation	3	2,435	2,435	8
SA 539	Bonneville Power Adm	Tieton Substation	1	5,498	5,498	9
SA 539	Bonneville Power Adm	Tieton Substation	1	853	853	10
SA 538	McNary Substation	Hinkle Substation	1	956	956	11
SA 538	McNary Substation	Hinkle Substation	1	118	118	12
SA 179	USBR Green Springs	Bonneville Power Adm	19	52,611	52,611	13
SA 179	USBR Green Springs	Bonneville Power Adm		3,391	3,391	14
RS 368	Malin Substation	Malin Substation		516,151	516,151	15
RS 368	Malin Substation	Malin Substation		24,118	24,118	16
SA 328	Bonneville Power Adm		6	37,147	37,147	17
SA 328	Bonneville Power Adm		5	3,533	3,533	18
SA 827	Bonneville Power Adm	Neff Substation	2	709	709	19
SA 827	Bonneville Power Adm	Neff Substation		93	93	20
SA 746	Goshen Substation	Various	216	1,321,976	1,321,976	21
SA 746	Goshen Substation	Various	276	170,911	170,911	22
SA 44	Various	Various		172,143	172,143	23
SA 44	Various	Various				24
SA 747	Goshen Substation	Various	89	612,581	612,581	25
SA 747	Goshen Substation	Various	82	52,811	52,811	26
SA 735	Cardwell-Merwin		21	115,463	115,463	27
SA 735	Cardwell-Merwin		27	14,769	14,769	28
SA 757	Various	Various		52,775	52,775	29
SA 299	Bonneville Power Adm	Various	16	108,967	108,967	30
SA 299	Bonneville Power Adm	Various	17	11,537	11,537	31
SA 881	Malin 500 Substation	Round Mountain Sub	52			32
SA 881	Malin 500 Substation	Round Mountain Sub	52			33
SA 899	Troutdale Substation	Troutdale Substation	19	98,402	98,402	34
			5,281	**15,241,847**	**15,129,193**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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.
		528	528	1
				2
3,985,821		67,947	4,053,768	3
		376,999	376,999	4
1,737,779		13,585	1,751,364	5
		101,367	101,367	6
100,603		156,908	257,511	7
		20,385	20,385	8
23,926		3,823	27,749	9
		4,539	4,539	10
3,401		600	4,001	11
		-2,085	-2,085	12
558,572		5,689	564,261	13
		32,925	32,925	14
		232,452	232,452	15
		21,132	21,132	16
169,407		123,895	293,302	17
		29,220	29,220	18
1,389		340	1,729	19
		388	388	20
6,424,187		1,525,264	7,949,451	21
		694,384	694,384	22
	1,165,238	47,112	1,212,350	23
		67	67	24
2,862,327		493,035	3,355,362	25
		204,559	204,559	26
623,286		91,073	714,359	27
		59,372	59,372	28
	267,171	10,705	277,876	29
455,266		160,309	615,575	30
		661,418	661,418	31
1,485,485		34,913	1,520,398	32
		126,970	126,970	33
541,479		21,923	563,402	34
71,429,114	**16,491,269**	**23,992,613**	**111,912,996**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Clatskanie People's Utility District	Clatskanie People's Utility Dist	Clatskanie People's Utility Dist	AD
2	Deseret Gen and Trans	Deseret Gen and Trans	Deseret Gen and Trans	OS
3	Deseret Gen and Trans	Deseret Gen and Trans	Deseret Gen and Trans	AD
4	Deseret Gen and Trans	various signatories	various signatories	NF
5	Deseret Gen and Trans	various signatories	various signatories	AD
6	Eagle Energy Partners I LP	various signatories	various signatories	NF
7	Energy Keepers, Inc.	various signatories	various signatories	NF
8	Eugene Water & Electric Board	NextEra Energy Resources, LLC	various signatories	LFP
9	Eugene Water & Electric Board	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
10	Eugene Water & Electric Board	various signatories	various signatories	NF
11	Evergreen Biopower LLC	NextEra Energy Resources, LLC	various signatories	LFP
12	Evergreen Biopower LLC	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
13	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
14	Exelon Generation Company, LLC	Bonneville Power Administration	Oregon Direct Access	AD
15	Exelon Generation Company, LLC	various signatories	various signatories	NF
16	Exelon Generation Company, LLC	various signatories	various signatories	AD
17	Exelon Generation Company, LLC	various signatories	various signatories	SFP
18	Fall River Rural Electric Cooperative, Inc.	Marysville Hydro Partners	Idaho Power Company	OS
19	Fall River Rural Electric Cooperative, Inc.	Marysville Hydro Partners	Idaho Power Company	AD
20	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	OS
21	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	AD
22	Idaho Power Company	Exxon Mobil	Nevada Power Company	LFP
23	Idaho Power Company	Exxon Mobil	Nevada Power Company	AD
24	Idaho Power Company	various signatories	various signatories	NF
25	Idaho Power Company	various signatories	various signatories	SFP
26	Idaho Power Company	various signatories	various signatories	AD
27	Los Angeles Department of Water & Power	various signatories	various signatories	NF
28	Los Angeles Department of Water & Power	various signatories	various signatories	SFP
29	Macquarie Energy LLC	various signatories	various signatories	NF
30	Macquarie Energy LLC	various signatories	various signatories	AD
31	Macquarie Energy LLC	various signatories	various signatories	SFP
32	MAG Energy Solutions, Inc.	various signatories	various signatories	NF
33	MAG Energy Solutions, Inc.	various signatories	various signatories	AD
34	Moon Lake Electric Association Inc.	Moon Lake Electric Association	Moon Lake Electric Association	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 899	Troutdale Substation	Troutdale Substation	19	8,535	8,535	1
RS 280	Various	Various	96	859,615	859,615	2
RS 280	Various	Various	75	73,850	73,850	3
SA 156	Various	Various		3,800	3,800	4
SA 156	Various	Various		636	636	5
SA 569	Various	Various		1,692	1,692	6
SA 815	Various	Various		70	70	7
SA 780	Various	Various				8
SA 780	Various	Various				9
SA 13	Various	Various				10
SA 874	Various	Various		53,538	53,538	11
SA 874	Various	Various		4,903	4,903	12
SA 847	Bonneville Power Adm	Various	1	5,552	5,552	13
SA 847	Bonneville Power Adm	Various	1	578	578	14
SA 759	Various	Various		16,524	16,524	15
SA 759	Various	Various		760	760	16
SA 760	Various	Various				17
RS 322	Targhee Substation	Goshen Substation				18
RS 322	Targhee Substation	Goshen Substation				19
SA 761	Foote Creek Sub	Various				20
SA 761	Foote Creek Sub	Various				21
SA 212	Trona Substation	Red Butte/Mona Sub	78	8,778	8,778	22
SA 212	Trona Substation	Red Butte/Mona Sub				23
SA 725	Antelope Substation	Various		3	3	24
SA 726	Various	Various		1,647	1,647	25
SA 726	Various	Various				26
SA 142	Various	Various		206,295	206,295	27
SA 143	Various	Various		5,020	5,020	28
SA 755	Various	Various		25,273	25,273	29
SA 755	Various	Various		4,061	4,061	30
SA 754	Various	Various		191	191	31
SA 903	Various	Various		13,323	13,323	32
SA 903	Various	Various		1,004	1,004	33
RS 302	Duchesne	Duchesne		18,568	18,568	34
			5,281	**15,241,847**	**15,129,193**	

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.
		9,136	9,136	1
3,406,634		1,696,769	5,103,403	2
		471,601	471,601	3
	35,590	1,425	37,015	4
		4,836	4,836	5
	19,500	782	20,282	6
	575	23	598	7
		72,538	72,538	8
		47,304	47,304	9
	8		8	10
310,318		44,863	355,181	11
		28,496	28,496	12
20,972		5,151	26,123	13
		14,366	14,366	14
	82,382	1,683,703	1,766,085	15
		138,106	138,106	16
	3,943	161	4,104	17
		138,699	138,699	18
		12,609	12,609	19
		37,629	37,629	20
		8,881	8,881	21
712,333		28,513	740,846	22
		-20,654	-20,654	23
	123,569	4,925	128,494	24
	15,396	630	16,026	25
		3,660	3,660	26
	1,149,280	47,070	1,196,350	27
	40,402	1,657	42,059	28
	206,928	8,371	215,299	29
		34,674	34,674	30
	1,741	69	1,810	31
	99,698	4,084	103,782	32
		8,134	8,134	33
		17,655	17,655	34
71,429,114	**16,491,269**	**23,992,613**	**111,912,996**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Moon Lake Electric Association Inc.	Moon Lake Electric Association	Moon Lake Electric Association	AD
2	Morgan Stanley Capital Group, Inc.	various signatories	various signatories	NF
3	Morgan Stanley Capital Group, Inc.	various signatories	various signatories	AD
4	Morgan Stanley Capital Group, Inc.	various signatories	various signatories	SFP
5	Municipal Energy Agency of Nebraska	various signatories	various signatories	AD
6	Municipal Energy Agency of Nebraska	various signatories	various signatories	AD
7	Navajo Tribal Utility Authority	Navajo Tribal Utility Authority	Navajo Tribal Utility Authority	FNO
8	Navajo Tribal Utility Authority	Navajo Tribal Utility Authority	Navajo Tribal Utility Authority	AD
9	Nevada Power Company	various signatories	various signatories	NF
10	Nevada Power Company	various signatories	various signatories	SFP
11	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	LFP
12	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	AD
13	NextEra Energy Resources, LLC	various signatories	various signatories	NF
14	NextEra Energy Resources, LLC	various signatories	various signatories	AD
15	Obsidian Renewables	Lakeview Airport 10	Portland General Electric	LFP
16	Pacific Gas & Electric Company			OS
17	Pacific Gas & Electric Company	various signatories	various signatories	NF
18	Portland General Electric Company			OS
19	Portland General Electric Company	various signatories	various signatories	NF
20	Portland General Electric Company	various signatories	various signatories	AD
21	Portland General Electric Company	various signatories	various signatories	SFP
22	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
23	Powerex Corporation	Bonneville Power Administration	CAISO	AD
24	Powerex Corporation	Powerex Corporation	CAISO	LFP
25	Powerex Corporation	Powerex Corporation	CAISO	AD
26	Powerex Corporation	Powerex Corporation	CAISO	LFP
27	Powerex Corporation	Powerex Corporation	CAISO	AD
28	Powerex Corporation	Powerex Corporation	CAISO	LFP
29	Powerex Corporation	Powerex Corporation	CAISO	AD
30	Powerex Corporation	Powerex Corporation	CAISO	LFP
31	Powerex Corporation	Powerex Corporation	CAISO	AD
32	Powerex Corporation	Powerex Corporation	CAISO	LFP
33	Powerex Corporation	Powerex Corporation	CAISO	AD
34	Powerex Corporation	various signatories	various signatories	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.
RS 302	Duchesne	Duchesne		1,515	1,515	1
SA 157	Various	Various		316,878	316,878	2
SA 157	Various	Various		15,757	15,757	3
SA 160	Various	Various		6,321	6,321	4
SA 307	Various	Various		120	120	5
SA 308	Various	Various				6
SA 894	Four Corners	Pinto-Four Corners	1	14,941	14,941	7
SA 894	Four Corners	Pinto-Four Corners	1	1,639	1,639	8
SA 455	Various	Various		16,311	16,311	9
SA 454	Various	Various		34,179	34,179	10
SA 733	Wallula Substation	Wala-MIDC path	103	53,577	53,577	11
SA 733	Wallula Substation	Wala-MIDC path	103	14,226	14,226	12
SA 236	Various	Various		1,497	1,497	13
SA 236	Various	Various		59	59	14
SA 880	Various	Various	10			15
RS 298	Sigurd-Glen Canyon	Pinto-Four Corners				16
SA 338	Various	Various		1,170	1,170	17
RS 137	Various	Various				18
SA 8	Various	Various		1,390	1,390	19
SA 8	Various	Various		7	7	20
SA 8	Various	Various		76,320	76,320	21
SA 169	Bonneville Power Adm	CRAG View Substation	83	321,300	321,300	22
SA 169	Bonneville Power Adm	CRAG View Substation	83	15,679	15,679	23
SA 700	Malin 500 Substation	Round Mountain Sub	67			24
SA 700	Malin 500 Substation	Round Mountain Sub	67			25
SA 701	Malin 500 Substation	Round Mountain Sub	67			26
SA 701	Malin 500 Substation	Round Mountain Sub	67			27
SA 702	Malin 500 Substation	Round Mountain Sub	66			28
SA 702	Malin 500 Substation	Round Mountain Sub	66			29
SA 748	Malin 500 Substation	Round Mountain Sub	50			30
SA 748	Malin 500 Substation	Round Mountain Sub	50			31
SA 749	Malin 500 Substation	Round Mountain Sub	150			32
SA 749	Malin 500 Substation	Round Mountain Sub	50			33
SA 47	Various	Various		174,881	174,881	34
			5,281	**15,241,847**	**15,129,193**	

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.
		1,605	1,605	1
	2,284,886	92,694	2,377,580	2
		235,674	235,674	3
	41,747	1,695	43,442	4
		8	8	5
		1,004	1,004	6
67,179		11,632	78,811	7
		6,102	6,102	8
	1,652	443	2,095	9
	199,135	7,967	207,102	10
2,095,338		848,548	2,943,886	11
		224,588	224,588	12
	176,545	7,106	183,651	13
		28,943	28,943	14
28,493		1,141	29,634	15
		135,015	135,015	16
	10,655	429	11,084	17
		3,314	3,314	18
	8,220	326	8,546	19
		253	253	20
	289,007	11,855	300,862	21
2,482,542		100,476	2,583,018	22
		151,144	151,144	23
2,970,969		69,826	3,040,795	24
		179,039	179,039	25
2,970,969		69,826	3,040,795	26
		179,042	179,042	27
2,970,969		69,826	3,040,795	28
		180,051	180,051	29
3,122,249		72,929	3,195,178	30
		25,344	25,344	31
2,819,690		66,723	2,886,413	32
		327,792	327,792	33
	620,981	25,246	646,227	34
71,429,114	**16,491,269**	**23,992,613**	**111,912,996**	

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 2019/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	various signatories	various signatories	AD
2	Powerex Corporation	various signatories	various signatories	SFP
3	Powerex Corporation	various signatories	various signatories	AD
4	PUD No. 1 of Cowlitz County	PUD No. 1 of Cowlitz County	Bonneville Power Administration	OS
5	PUD No. 1 of Cowlitz County	PUD No. 1 of Cowlitz County	Bonneville Power Administration	AD
6	Rainbow Energy Marketing Corporation	various signatories	various signatories	NF
7	Rainbow Energy Marketing Corporation	various signatories	various signatories	AD
8	Rainbow Energy Marketing Corporation	various signatories	various signatories	SFP
9	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	LFP
10	Sacramento Municipal Utility District	Sacramento Municipal Utility Dist	Sacramento Municipal Utility Dist	AD
11	Salt River Project	Salt River Project	Salt River Project	LFP
12	Salt River Project	Salt River Project	Salt River Project	AD
13	Salt River Project	various signatories	various signatories	NF
14	Salt River Project	various signatories	various signatories	SFP
15	Shell Energy North America (US), L.P.	NextEra Energy Resources, LLC	PUD No. 2 of Grant County	LFP
16	Shell Energy North America (US), L.P.	various signatories	various signatories	NF
17	Shell Energy North America (US), L.P.	various signatories	various signatories	AD
18	Shell Energy North America (US), L.P.	various signatories	various signatories	SFP
19	Shell Energy North America (US), L.P.	various signatories	various signatories	AD
20	Sierra Pacific Power Company			OS
21	Sierra Pacific Power Company			AD
22	Southern California Edison Company			OS
23	Southern California Edison Company	various signatories	various signatories	NF
24	Southern California Edison Company	various signatories	various signatories	AD
25	Southern California Public Power	Powerex Corporation	Southern California Public Power	NF
26	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
27	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
28	Tenaska Power Services Co.	various signatories	various signatories	NF
29	Tenaska Power Services Co.	various signatories	various signatories	AD
30	Tenaska Power Services Co.	various signatories	various signatories	SFP
31	Tenaska Power Services Co.	various signatories	various signatories	AD
32	The Energy Authority, Inc.	various signatories	various signatories	NF
33	The Energy Authority, Inc.	various signatories	various signatories	AD
34	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project	various signatories	LFP
	TOTAL			

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/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 47	Various	Various		11,722	11,722	1
SA 151	Various	Various		5,003	5,003	2
SA 151	Various	Various		655	655	3
RS 234	Swift Unit No. 2	Woodland Substation				4
RS 234	Swift Unit No. 2	Woodland Substation				5
SA 316	Various	Various		7,448	7,448	6
SA 316	Various	Various		259	259	7
SA 261	Various	Various				8
SA 863	Malin Substation	Malin Substation	31	125,066	125,066	9
SA 863	Malin Substation	Malin Substation	31	12,560	12,560	10
SA 809	Enel Cove Fort	Red Butte Substation	26	141,357	141,357	11
SA 809	Enel Cove Fort	Red Butte Substation	26	15,408	15,408	12
SA 557	Various	Various		120	120	13
SA 557	Various	Various		510	510	14
SA 791	Wallula Substation	Wala-MIDC path		59,659	59,659	15
SA 23	Various	Various		390,545	390,545	16
SA 23	Various	Various		14,271	14,271	17
SA 162	Various	Various		25,237	25,237	18
SA 162	Various	Various		6,337	6,337	19
RS 674	Sigurd Substation	Utah-Nevada Border				20
RS 674	Sigurd Substation	Utah-Nevada Border				21
RS 298	Sigurd-Glen Canyon	Pinto-Four Corners				22
SA 642	Various	Various		37,781	37,781	23
SA 642	Various	Various		51	51	24
SA 629	Tieton Substation	Various		38	38	25
SA 779	Yellowtail Sub	Wyodak Substation	4	19,220	19,220	26
SA 779	Yellowtail Sub	Wyodak Substation	4	1,675	1,675	27
SA 125	Various	Various		23,580	23,580	28
SA 125	Various	Various		70	70	29
SA 126	Various	Various		3,342	3,342	30
SA 126	Various	Various				31
SA 310	Various	Various		14,471	14,471	32
SA 310	Various	Various		300	300	33
SA 568	South Milford Sub	Mona Substation	11	59,638	59,638	34
			5,281	**15,241,847**	**15,129,193**	

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.
		30,231	30,231	1
	1,148,340	46,252	1,194,592	2
		378	378	3
		123,059	123,059	4
		15,346	15,346	5
	48,192	1,959	50,151	6
		9,162	9,162	7
	15,308	628	15,936	8
589,619		23,863	613,482	9
		32,318	32,318	10
775,809		31,398	807,207	11
		47,304	47,304	12
	1,211	49	1,260	13
	3,984	162	4,146	14
1,133,537		177,660	1,311,197	15
	1,748,884	138,141	1,887,025	16
		85,567	85,567	17
	282,145	11,517	293,662	18
		1,334	1,334	19
		33,147	33,147	20
		3,013	3,013	21
		135,015	135,015	22
	2,450,519	904,697	3,355,216	23
		295,919	295,919	24
		32,287	32,287	25
124,127		5,025	129,152	26
		7,568	7,568	27
	227,012	125,131	352,143	28
		9,085	9,085	29
	24,355	976	25,331	30
		280	280	31
	106,265	4,268	110,533	32
		2,511	2,511	33
341,364		49,948	391,312	34
71,429,114	**16,491,269**	**23,992,613**	**111,912,996**	

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 2019/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	Thermo No. 1 BE-01, LLC	Thermo Geothermal Project	various signatories	AD
2	TransAlta Energy Marketing (U.S.) Inc.	various signatories	various signatories	NF
3	TransAlta Energy Marketing (U.S.) Inc.	various signatories	various signatories	AD
4	TransAlta Energy Marketing (U.S.) Inc.	various signatories	various signatories	SFP
5	Tri-State Gen and Trans	various signatories	Tri-State Gen and Trans	FNO
6	Tri-State Gen and Trans	various signatories	Tri-State Gen and Trans	AD
7	Tri-State Gen and Trans	various signatories	various signatories	NF
8	Tucson Power Company	various signatories	various signatories	NF
9	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
10	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
11	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
12	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
13	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
14	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
15	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
16	Utah Associated Municipal Power	various signatories	various signatories	NF
17	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
18	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
19	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric	OS
20	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric	AD
21	Westar Energy, Inc.	various signatories	various signatories	NF
22	Westar Energy, Inc.	various signatories	various signatories	AD
23	Western Area Power Administration	Western Area Power Administration		OS
24	Western Area Power Administration	Western Area Power Administration		AD
25	Western Area Power Administration	Western Area Power Administration		OS
26	Western Area Power Administration	Western Area Power Administration		AD
27	Western Area Power Administration	Western Area Power Administration	various signatories	OS
28	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
29	Western Area Power Administration	Western Area Power Adm CO River	Western Area Power Administration	AD
30	Western Area Power Adm CO River	Western Area Power Adm CO River	various signatories	NF
31	Western Area Power Adm CO MO	Western Area Power Adm CO River	various signatories	NF
32	Western Area Power Adm CO MO	Western Area Power Adm CO River	various signatories	AD
33	Accrual			
34				
	TOTAL			

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/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 568	South Milford Sub	Mona Substation	11	6,444	6,444	1
SA 127	Various	Various		37,090	37,090	2
SA 127	Various	Various		2,757	2,757	3
SA 127	Various	Various		453	453	4
SA 628	Dave Johnston Sub	Thermopolis Sub	17	108,632	108,632	5
SA 628	Dave Johnston Sub	Thermopolis Sub	16	10,693	10,693	6
SA 33	Various	Various		476	476	7
SA 180	Various	Various		2,010	2,010	8
SA 506	Walla Walla Sub	Burbank Pumps	1	2,236	2,236	9
SA 506	Walla Walla Sub	Burbank Pumps	1	4	4	10
RS 286	Various	Various		21,010	21,010	11
RS 286	Various	Various		1,019	1,019	12
RS 67	Redmond Substation	Crooked River Pumps		10,047	10,047	13
RS 297	Various	Various	501	2,695,851	2,695,851	14
RS 297	Various	Various	440	271,099	271,099	15
SA 9	Various	Various		100	100	16
RS 637	Various	Various	78	553,783	553,783	17
RS 637	Various	Various	77	62,023	62,023	18
RS 591	Pelton Reregulating	Round Butte Sub		55,750	55,750	19
RS 591	Pelton Reregulating	Round Butte Sub		6,814	6,814	20
SA 813	Various	Various				21
SA 813	Various	Various		273	273	22
RS 262	Various	Various	330	1,666,231	1,566,257	23
RS 262	Various	Various	330	168,185	158,094	24
RS 263	Various	Various		44,040	41,397	25
RS 263	Various	Various		4,111	3,858	26
RS 684	Dave Johnston Sub	Various				27
SA 175	Wyoming Distribution	Wyoming Distribution	1	9,187	9,187	28
SA 175	Various	Wyoming Distribution	1	5	5	29
SA 132	Various	Various				30
SA 724	Various	Various		188	188	31
SA 724	Various	Various		527	527	32
				71,144	71,451	33
						34
			5,281	**15,241,847**	**15,129,193**	

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.
		24,404	24,404	1
	372,868	15,043	387,911	2
		17,214	17,214	3
	3,230	128	3,358	4
480,206		83,738	563,944	5
		34,880	34,880	6
	3,408	136	3,544	7
	14,071	563	14,634	8
8,380		10,671	19,051	9
		402	402	10
		21,009	21,009	11
		1,019	1,019	12
11,223			11,223	13
15,304,609		2,569,218	17,873,827	14
		961,964	961,964	15
	1,652	66	1,718	16
2,386,727		391,576	2,778,303	17
		249,401	249,401	18
		109,725	109,725	19
		9,975	9,975	20
	402	16	418	21
		2,285	2,285	22
2,322,553		563,188	2,885,741	23
		264,317	264,317	24
		36,405	36,405	25
		4,047	4,047	26
				27
39,247		42,394	81,641	28
		-1,276	-1,276	29
	1,151	46	1,197	30
	1,445	57	1,502	31
		4,151	4,151	32
		320,321	320,321	33
				34
71,429,114	**16,491,269**	**23,992,613**	**111,912,996**	

Schedule Page: 328 Line No.: 1 Column: d

Transmission service under the Open Access Transmission Tariff (1st Revised 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: d

Transmission service under the Open Access Transmission Tariff (1st Revised 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.: 2 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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

This footnote applies to all occurrences of "various signatories" on pages 328-330. Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 3 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 when the Cholla Plant, Unit 4 has been retired from service and all costs of terminating Unit 4 have been paid. See also page 332, Transmission of electricity by others, in this Form No. 1.

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

Glenn Canyon/Four Corners substation

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: d

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

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

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

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. 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.: 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

2018 transmission and ancillary services.

Schedule Page: 328 Line No.: 7 Column: d

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

Schedule Page: 328 Line No.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 8 Column: d

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

Schedule Page: 328 Line No.: 8 Column: m

2018 transmission and ancillary services.

Schedule Page: 328 Line No.: 9 Column: d

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

Schedule Page: 328 Line No.: 9 Column: f

Long Hollow, WY switching station

Schedule Page: 328 Line No.: 9 Column: g

Long Hollow, WY switching station

Schedule Page: 328 Line No.: 9 Column: m

Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328 Line No.: 10 Column: d

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

Schedule Page: 328 Line No.: 10 Column: f

Long Hollow, WY switching station

Schedule Page: 328 Line No.: 10 Column: g

Long Hollow, WY switching station

Schedule Page: 328 Line No.: 10 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328 Line No.: 11 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.: 11 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 895) terminating on April 30, 2024.

Schedule Page: 328 Line No.: 11 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 12 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 895) terminating on April 30, 2024.

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

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328 Line No.: 13 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.: 13 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.: 14 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.: 14 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328 Line No.: 15 Column: d

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

Schedule Page: 328 Line No.: 15 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 16 Column: d

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.: 16 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.: 17 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.: 17 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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: 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

2018 transmission and ancillary services.

Schedule Page: 328 Line No.: 20 Column: c

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

Schedule Page: 328 Line No.: 20 Column: d

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

Schedule Page: 328 Line No.: 20 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 21 Column: 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

2018 transmission and ancillary services.

Schedule Page: 328 Line No.: 22 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.: 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: 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

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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: 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
2018 transmission and ancillary services.

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: 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
2018 transmission and ancillary services.

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: 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
2018 transmission and ancillary services.

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: 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
2018 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 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 Bonneville Power Administration ("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 Bonneville Power Administration ("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

2018 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

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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

2018 transmission and ancillary services. 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

2018 transmission and ancillary services. 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

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
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 15 Column: d
Legacy contract (5th Revised Rate Schedule 368) executed between PacifiCorp and Bonneville Power Administration 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 Bonneville Power Administration 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
2018 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
2018 transmission and ancillary services. 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
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 25 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.: 25 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.: 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
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 27 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.: 27 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.: 27 Column: g
Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 27 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.: 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
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 29 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 29 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 30 Column: 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.: 30 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.: 31 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.: 31 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.1 Line No.: 32 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 881) terminating on February 28, 2023.

Schedule Page: 328.1 Line No.: 32 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 33 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 881) terminating on February 28, 2023.

Schedule Page: 328.1 Line No.: 33 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 34 Column: b
This footnote applies to all occurrences of “Clatskanie People's Utility Dist” on pages 328-330. Complete name is Clatskanie People's Utility District.

Schedule Page: 328.1 Line No.: 34 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 899) terminating on December 31, 2020.

Schedule Page: 328.1 Line No.: 34 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 1 Column: 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.: 1 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.2 Line No.: 2 Column: a
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.: 2 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.: 2 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.: 3 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.: 3 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.2 Line No.: 4 Column: d

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

Schedule Page: 328.2 Line No.: 4 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 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: 328.2 Line No.: 5 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.2 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: 328.2 Line No.: 6 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 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: 328.2 Line No.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 8 Column: d

Transmission resale service under the Open Access Transmission Tariff (Service Agreement 780). Termination upon mutual consent.

Schedule Page: 328.2 Line No.: 8 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.: 9 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.: 9 Column: d

Transmission resale service under the Open Access Transmission Tariff (Service Agreement 780). Termination upon mutual consent.

Schedule Page: 328.2 Line No.: 9 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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.: 11 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.: 11 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.: 12 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.: 12 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.2 Line No.: 13 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.: 13 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.: 14 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.: 14 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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

Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 16 Column: d

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

Schedule Page: 328.2 Line No.: 16 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.2 Line No.: 17 Column: d

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

Schedule Page: 328.2 Line No.: 17 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 18 Column: d

Legacy contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural Electric Cooperative, Inc. 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.: 18 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 19 Column: d

Legacy contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural Electric Cooperative, Inc. 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.: 19 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 20 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.: 20 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.: 21 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.: 21 Column: m
2018 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 22 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 212) terminating on May 31, 2024.

Schedule Page: 328.2 Line No.: 22 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 23 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (9th Revised Service Agreement 212) terminating on May 31, 2024.

Schedule Page: 328.2 Line No.: 23 Column: m
Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.2 Line No.: 24 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 24 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 25 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 25 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 26 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 26 Column: m
2018 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 27 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 27 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 28 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 28 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Schedule Page: 328.2 Line No.: 30 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 31 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 31 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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
2018 transmission and ancillary services.

Schedule Page: 328.2 Line No.: 34 Column: d
Legacy contract (3rd Revised Rate Schedule 302) executed between PacifiCorp and Moon Lake Electric Association Inc. for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Either party may terminate the agreement at any time after October 14, 2016, by providing two years written notice.

Schedule Page: 328.2 Line No.: 34 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.3 Line No.: 1 Column: d

Legacy contract (3rd Revised Rate Schedule 302) executed between PacifiCorp and Moon Lake Electric Association Inc. 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.: 1 Column: m

2018 transmission and ancillary services.

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: 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

2018 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 4 Column: d

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

Schedule Page: 328.3 Line No.: 4 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 5 Column: d

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

Schedule Page: 328.3 Line No.: 5 Column: m

2018 transmission and ancillary services.

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

2018 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 7 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.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 8 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.: 8 Column: m

2018 transmission and ancillary services.

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: 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 11 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.: 11 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.: 12 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.: 12 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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: 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

2018 transmission and ancillary services.

Schedule Page: 328.3 Line No.: 15 Column: c

This footnote applies to all occurrences of “Portland General Electric” on pages 328-330. Complete name is Portland General Electric Company.

Schedule Page: 328.3 Line No.: 15 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 880) terminating on September 29, 2024.

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: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 16 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 16 Column: d

Legacy contract (Rate Schedule 298) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge and phase shifting transformers at Sigurd-Glen Canyon 230kV transmission line and Pinto-Four Corners 345kV transmission line terminating on February 12, 2020.

Schedule Page: 328.3 Line No.: 16 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.: 17 Column: d

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

Schedule Page: 328.3 Line No.: 17 Column: m

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

Schedule Page: 328.3 Line No.: 18 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 18 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 18 Column: d

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 allows for automatic one-year renewals after initial one-year term.

Schedule Page: 328.3 Line No.: 18 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.: 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 20 Column: d

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

Schedule Page: 328.3 Line No.: 20 Column: m

2018 transmission and ancillary services.

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: 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.: 22 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.: 22 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 23 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.: 23 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.3 Line No.: 24 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.: 24 Column: m

Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 25 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.: 25 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.3 Line No.: 26 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.: 26 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 27 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.: 27 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.3 Line No.: 28 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.: 28 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 29 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.: 29 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.3 Line No.: 30 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 748) terminating on December 31, 2023.

Schedule Page: 328.3 Line No.: 30 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 31 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 748) terminating on December 31, 2023.

Schedule Page: 328.3 Line No.: 31 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.3 Line No.: 32 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 749) terminating on December 31, 2023.

Schedule Page: 328.3 Line No.: 32 Column: m
Scheduling, system control and dispatch service.

Schedule Page: 328.3 Line No.: 33 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 749) terminating on December 31, 2023.

Schedule Page: 328.3 Line No.: 33 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.3 Line No.: 34 Column: d

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

Schedule Page: 328.3 Line No.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 1 Column: d

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

Schedule Page: 328.4 Line No.: 1 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.4 Line No.: 2 Column: d

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

Schedule Page: 328.4 Line No.: 2 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 3 Column: d

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

Schedule Page: 328.4 Line No.: 3 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 4 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.: 4 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.: 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: 328.4 Line No.: 5 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.: 5 Column: m

2018 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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: d

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

Schedule Page: 328.4 Line No.: 8 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 9 Column: b

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.: 9 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.: 9 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 10 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.: 10 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.4 Line No.: 11 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.: 11 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 12 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.: 12 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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: 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: 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.: 15 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 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: 328.4 Line No.: 16 Column: m

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

Schedule Page: 328.4 Line No.: 17 Column: d

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

Schedule Page: 328.4 Line No.: 17 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 18 Column: d

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

Schedule Page: 328.4 Line No.: 18 Column: m

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.: 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

2018 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 20 Column: a

This footnote applies to all occurrences of Sierra Pacific Power Company on page 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.: 20 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 20 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 20 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.: 20 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.: 21 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 21 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 21 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.: 21 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 22 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 22 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.4 Line No.: 22 Column: d

Use of Facilities Agreement pertaining to the legacy contract (Rate Schedule 298) for phase shifting transformers at Sigurd-Glen Canyon 230kV transmission line and Pinto-Four Corners 345kV transmission line, terminating on February 12, 2020.

Schedule Page: 328.4 Line No.: 22 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.: 23 Column: d

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

Schedule Page: 328.4 Line No.: 23 Column: m

Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.4 Line No.: 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

2018 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 25 Column: a

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: 328.4 Line No.: 25 Column: d

Small Generator Interconnection Agreement (Service Agreement 629) executed between PacifiCorp and Southern California Public Power Authority which terminated on November 30, 2019.

Schedule Page: 328.4 Line No.: 25 Column: m

Unauthorized use of transmission service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.4 Line No.: 26 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 779) which terminated on August 31, 2024.

Schedule Page: 328.4 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 27 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 779) which terminated on August 31, 2024.

Schedule Page: 328.4 Line No.: 27 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.4 Line No.: 28 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 28 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 29 Column: 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.: 29 Column: m
2018 transmission and ancillary services.

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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 31 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 31 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 32 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 32 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 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: 328.4 Line No.: 33 Column: m
2018 transmission and ancillary services.

Schedule Page: 328.4 Line No.: 34 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 568) terminating on April 30, 2029.

Schedule Page: 328.4 Line No.: 34 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.: 1 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.: 1 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.5 Line No.: 2 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.5 Line No.: 2 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 3 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.5 Line No.: 3 Column: m
2018 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 4 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.5 Line No.: 4 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 5 Column: a
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.: 5 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.: 5 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.: 6 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.: 6 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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: 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 9 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.: 9 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.: 10 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.: 10 Column: m
2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.5 Line No.: 11 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.: 11 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.: 11 Column: m
Energy consumption for charge for deliveries at and below 138kV.

Schedule Page: 328.5 Line No.: 12 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.: 12 Column: m
2018 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 13 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.: 14 Column: a

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.: 14 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.: 14 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.: 15 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.: 15 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

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. Generation regulation and frequency response service.

Schedule Page: 328.5 Line No.: 17 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.: 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: 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.: 18 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.5 Line No.: 19 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.: 19 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.5 Line No.: 20 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.: 20 Column: m

2018 transmission and ancillary services.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 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: 328.5 Line No.: 22 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 23 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 23 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: 328.5 Line No.: 23 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.5 Line No.: 24 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 24 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: 328.5 Line No.: 24 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 25 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 25 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 terminates upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 25 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.5 Line No.: 26 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.5 Line No.: 26 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 terminates upon three years after written notice and mutual consent.

Schedule Page: 328.5 Line No.: 26 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 27 Column: d

Legacy contract (Rate Schedule 684) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also page 332, Transmission of electricity by others, in this Form No. 1.

Schedule Page: 328.5 Line No.: 28 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 28 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 29 Column: b

This footnote applies to all occurrences of "Western Area Power Adm CO River" on pages 328-330. Complete name is Western Area Power Administration Colorado River Storage Project.

Schedule Page: 328.5 Line No.: 29 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 175).

Schedule Page: 328.5 Line No.: 29 Column: m

2018 transmission and ancillary services. Refunds for transmission services pursuant to FERC Docket No. ER17-219-002.

Schedule Page: 328.5 Line No.: 30 Column: d

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

Schedule Page: 328.5 Line No.: 30 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.5 Line No.: 31 Column: a

This footnote applies to all occurrences of "Western Area Power Adm CO MO" on pages 328-330. Complete name is Western Area Power Administration Colorado Missouri.

Schedule Page: 328.5 Line No.: 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

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.: 32 Column: m

2018 transmission and ancillary services.

Schedule Page: 328.5 Line No.: 33 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 2019/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	Adams Solar Center LLC	LFP					-35,661	-35,661
2	Adams Solar Center LLC	OS					-9,082	-9,082
3	Arizona Public Service	AD					-27,542	-27,542
4	Arizona Public Service	NF	55,061	55,061	387,199			387,199
5	Arizona Public Service	LFP	1,314,000	1,314,000	586,611			586,611
6	Arizona Public Service	OS					52,683	52,683
7	Arizona Public Service	SFP	96,561	96,561	728,316			728,316
8	Ashland, City of	FNS	2,467	2,467		23,755		23,755
9	Avista Corporation	AD					-1,906	-1,906
10	Avista Corporation	FNS	58,789	58,803	277,574			277,574
11	Avista Corporation	NF	40,004	41,002	467,063			467,063
12	Avista Corporation	SFP	673,284	685,577	1,971,429			1,971,429
13	Basin Elect. Power Coop	NF	3,783	3,783	5,637			5,637
14	Big Horn Rural Electric	OLF	36,065	36,065			162,290	162,290
15	Black Hills Power, Inc.	AD					-2,850	-2,850
16	Black Hills Power, Inc.	NF	40	40	40			40
	TOTAL		22,624,955	22,879,489	123,126,897	410,546	22,287,825	145,825,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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.	OS					14,436	14,436
2	Black Hills Power, Inc.	SFP	33,621	33,621	92,415			92,415
3	Bonneville Power Admin	AD					5,651,535	5,651,535
4	Bonneville Power Admin	FNS	3,412	3,489	5,970,389			5,970,389
5	Bonneville Power Admin	LFP	5,026,307	5,137,779	52,997,354			52,997,354
6	Bonneville Power Admin	NF	1,062,208	1,084,314	3,472,693			3,472,693
7	Bonneville Power Admin	OLF	4,239,591	4,334,671	19,829,076			19,829,076
8	Bonneville Power Admin	OS					17,109,578	17,109,578
9	Bonneville Power Admin	SFP	333,453	340,854	1,176,411			1,176,411
10	CA Ind Sys Operator	AD					19,365	19,365
11	CA Ind Sys Operator	OS					2,158,634	2,158,634
12	CA Ind Sys Operator	SFP				385,372		385,372
13	Deseret Gen and Trans	LFP	853,847	853,847	3,304,078			3,304,078
14	Deseret Gen and Trans	NF	8,337	8,337	51,272			51,272
15	Elbe Solar Center, LLC	LFP					-169,828	-169,828
16	Elbe Solar Center, LLC	OS					-44,598	-44,598
	TOTAL		22,624,955	22,879,489	123,126,897	410,546	22,287,825	145,825,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Flathead Elect Coop Inc	OS					99,437	99,437
2	Hermiston Gen Co L.P.	OS					205,960	205,960
3	Idaho Power Company	AD					-72,096	-72,096
4	Idaho Power Company	FNS			12,228			12,228
5	Idaho Power Company	LFP	4,961,516	4,961,516	15,436,629			15,436,629
6	Idaho Power Company	NF	51,381	51,381	305,837			305,837
7	Idaho Power Company	OLF					7,440	7,440
8	Idaho Power Company	OS					-1,532,485	-1,532,485
9	Idaho Power Company	SFP	84,280	84,280	2,443,215			2,443,215
10	LA Dept. of Water & Pwr	OS					360	360
11	LA Dept. of Water & Pwr	SFP	864	864	3,492			3,492
12	Moon Lake Elect. Assoc.	FNS	19	19			260,104	260,104
13	Morgan City Corporation	LFP				1,419		1,419
14	Nevada Power Company	AD					-40,124	-40,124
15	Nevada Power Company	NF	85,556	85,556	370,821			370,821
16	Nevada Power Company	OS					214,607	214,607
	TOTAL		22,624,955	22,879,489	123,126,897	410,546	22,287,825	145,825,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Nevada Power Company	SFP	18,432	18,432	82,085			82,085
2	NorthWestern Corp.	NF	25,707	26,087	99,408			99,408
3	NorthWestern Corp.	OS					4,961	4,961
4	NorthWestern Corp.	SFP			43,846			43,846
5	Platte River Pwr Auth	LFP	219,375	219,375	849,352			849,352
6	Platte River Pwr Auth	OS					19,353	19,353
7	Portland Gen. Electric	LFP	105,024	105,024	75,360			75,360
8	Portland Gen. Electric	NF	2,435	2,435	2,402			2,402
9	Portland Gen. Electric	OLF					1,000	1,000
10	Portland Gen. Electric	OS		4,713			7,481	7,481
11	Public Service Co of CO	LFP	438,800	438,800	1,062,752			1,062,752
12	Public Service CO of NM	AD					-17	-17
13	Public Service CO of NM	NF			281			281
14	Public Service CO of NM	OS					27	27
15	Salt River Project	NF	1,400	1,400	8,638			8,638
16	Salt River Project	OS					1,246	1,246
	TOTAL		22,624,955	22,879,489	123,126,897	410,546	22,287,825	145,825,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Sierra Pacific Power Co	NF	1,201	1,201	6,742			6,742
2	Sierra Pacific Power Co	OS					39,838	39,838
3	Sierra Pacific Power Co	SFP	80,256	80,256	274,372			274,372
4	Surprise Valley Electr.	AD					693	693
5	Surprise Valley Electr.	OLF					6,523	6,523
6	Tri-State Gen and Trans	LFP	438,800	438,800	1,062,752			1,062,752
7	Tri-State Gen and Trans	NF	14,954	14,954	74,770			74,770
8	Tri-State Gen and Trans	OS					11,968	11,968
9	Tucson Electric Pwr Co.	AD					-755	-755
10	Western Area Power Admn	AD					-240	-240
11	Western Area Power Admn	FNS	901,615	901,615	6,555,320			6,555,320
12	Western Area Power Admn	LFP	899,250	899,250	2,403,334			2,403,334
13	Western Area Power Admn	NF	267,375	267,375	624,329			624,329
14	Western Area Power Admn	OS					788,095	788,095
15	Western Area Power Admn	SFP	185,885	185,885	11,375			11,375
16	Westport Field Srv LLC	AD					-128,664	-128,664
	TOTAL		22,624,955	22,879,489	123,126,897	410,546	22,287,825	145,825,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Westport Field Srv LLC	LFP					-2,403,434	-2,403,434
2	Accrual						-80,507	-80,507
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		22,624,955	22,879,489	123,126,897	410,546	22,287,825	145,825,268

Schedule Page: 332 Line No.: 1 Column: b
Adams Solar Center LLC - contract termination date: October 30, 2036.

Schedule Page: 332 Line No.: 1 Column: g
Reimbursement for third party services.

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.: 5 Column: b
Arizona Public Service Company - Legacy contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PacifiCorp and Arizona Public Service Company, Rate Schedule 436). The contract terminates when the Cholla Plant, Unit 4 has been retired from service and all costs of terminating Unit 4 have been paid. See also page 328-330, Transmission of electricity for others in this Form No. 1.

Schedule Page: 332 Line No.: 6 Column: b
Ancillary services.

Schedule Page: 332 Line No.: 6 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 9 Column: g
Settlement adjustment.

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.: 1 Column: b
Ancillary services.

Schedule Page: 332.1 Line No.: 1 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: October 1, 2019; November 1, 2019; November 1, 2020; January 1, 2021; July 1, 2021; September 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; October 1, 2023; December 1, 2023; January 1, 2024; July 1, 2024; September 1, 2024; October 1, 2024; November 1, 2024; October 1, 2027; November 1, 2033 and evergreen.

Schedule Page: 332.1 Line No.: 7 Column: b
Bonneville Power Administration - contract termination dates: September 30, 2023; 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. Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 332.1 Line No.: 13 Column: b
Deseret Generation and Transmission Co-operative - contract termination date: November 1, 2022.

Schedule Page: 332.1 Line No.: 15 Column: b
Elbe Solar Center, LLC - contract termination date: October 30, 2036.

Schedule Page: 332.1 Line No.: 15 Column: g
Reimbursement for third party services.

Schedule Page: 332.1 Line No.: 16 Column: b
Ancillary services.

Schedule Page: 332.1 Line No.: 16 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 1 Column: a
Complete name is Flathead Electric Cooperative, Inc.

Schedule Page: 332.2 Line No.: 1 Column: b
Use of facilities.

Schedule Page: 332.2 Line No.: 1 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 2 Column: a
Complete name is Hermiston Generating Company, L.P. who operates the Hermiston Plant and is jointly owned. PacifiCorp owns 50% of the Hermiston plant.

Schedule Page: 332.2 Line No.: 2 Column: b
Use of facilities.

Schedule Page: 332.2 Line No.: 2 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 332.2 Line No.: 3 Column: g
Settlement adjustment.

Schedule Page: 332.2 Line No.: 5 Column: b
Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025.

Schedule Page: 332.2 Line No.: 7 Column: b
Idaho Power Company - The contract termination date of August 31, 2022, shall automatically renew for each successive one year period thereafter unless or until the earlier of (i) one year following Department of Energy’s receipt of written notice by PacifiCorp, if due to a re-configuration of its transmission system PacifiCorp no longer needs use of the Department of Energy, Scoville Facilities; or (ii) upon mutual agreement of the parties.

Schedule Page: 332.2 Line No.: 7 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 8 Column: b
Ancillary services.

Schedule Page: 332.2 Line No.: 8 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 10 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.: 10 Column: b
Ancillary services.

Schedule Page: 332.2 Line No.: 10 Column: g
Ancillary services.

Schedule Page: 332.2 Line No.: 12 Column: a
Complete name is Moon Lake Electric Association Inc.

Schedule Page: 332.2 Line No.: 12 Column: g
Use of facilities.

Schedule Page: 332.2 Line No.: 13 Column: b
Morgan City Corporation - contract termination date: Evergreen.

Schedule Page: 332.2 Line No.: 14 Column: a
This footnote applies to all occurrences of "Nevada Power Company" on page 332. Nevada Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 332.2 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 332.2 Line No.: 14 Column: g
Settlement adjustment.

Schedule Page: 332.2 Line No.: 16 Column: b
Ancillary services.

Schedule Page: 332.2 Line No.: 16 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 3 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 3 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 5 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.: 5 Column: b
Platte River Power Authority - contract termination date: October 31, 2022.

Schedule Page: 332.3 Line No.: 6 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 6 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 7 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.: 7 Column: b
Portland General Electric Company - contract termination date: April 1, 2022.

Schedule Page: 332.3 Line No.: 9 Column: b
Portland General Electric Company - contract termination date: Upon two years written notice.

Schedule Page: 332.3 Line No.: 9 Column: g
Use of facilities.

Schedule Page: 332.3 Line No.: 10 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 10 Column: g
Ancillary services.

Schedule Page: 332.3 Line No.: 11 Column: a
Complete name is Public Service Company of Colorado.

Schedule Page: 332.3 Line No.: 11 Column: b
Public Service Company of Colorado - contract termination date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.3 Line No.: 12 Column: a
This footnote applies to all occurrences of "Public Service Co of NM" on page 332. Complete name is Public Service Company of New Mexico.

Schedule Page: 332.3 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 332.3 Line No.: 12 Column: g
Settlement adjustment.

Schedule Page: 332.3 Line No.: 14 Column: b
Ancillary services.

Schedule Page: 332.3 Line No.: 14 Column: g
Ancillary services.

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: a

This footnote applies to all occurrences of "Sierra Pacific Power Co" on page 332. Sierra Pacific Power Company is a wholly owned subsidiary of NV Energy, Inc., which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company, PacifiCorp's indirect parent company.

Schedule Page: 332.4 Line No.: 2 Column: b

Ancillary services.

Schedule Page: 332.4 Line No.: 2 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 4 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.: 4 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 4 Column: g

Settlement adjustment.

Schedule Page: 332.4 Line No.: 5 Column: b

Surprise Valley Electrification Corp. - contract termination date: Evergreen.

Schedule Page: 332.4 Line No.: 5 Column: g

Use of facilities.

Schedule Page: 332.4 Line No.: 6 Column: a

This footnote applies to all occurrences of "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.: 6 Column: b

Tri-State Generation and Transmission Association, Inc. - contract termination date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.4 Line No.: 8 Column: b

Ancillary services.

Schedule Page: 332.4 Line No.: 8 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 9 Column: a

The complete name is Tucson Electric Power Company.

Schedule Page: 332.4 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 9 Column: g

Settlement adjustment.

Schedule Page: 332.4 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 332.4 Line No.: 10 Column: g
Settlement adjustment.

Schedule Page: 332.4 Line No.: 12 Column: b
Western Area Power Administration - contract termination date: May 31, 2022.

Schedule Page: 332.4 Line No.: 14 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: 332.4 Line No.: 14 Column: g
Ancillary services. Use of facilities.

Schedule Page: 332.4 Line No.: 16 Column: b
Settlement adjustment.

Schedule Page: 332.4 Line No.: 16 Column: g
Settlement adjustment.

Schedule Page: 332.5 Line No.: 1 Column: b
Westport Field Services, LLC - contract termination date: Evergreen.

Schedule Page: 332.5 Line No.: 1 Column: g
Reimbursement for third party services.

Schedule Page: 332.5 Line No.: 2 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 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,376,461
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	Carbon County Economic Development Corporation	5,000
10	Clatsop Economic Development Resources	5,000
11	Economic Development for Central Oregon	7,500
12	Forth (Drive Oregon)	12,500
13	Greater Yakima Chamber of Commerce	5,000
14	Klamath County Economic Development Association	5,000
15	Laramie Chamber of Business Alliance	5,000
16	Ogden-Weber Chamber of Commerce	6,000
17	Oregon Business Council	33,447
18	Oregon Economic Development Association	13,500
19	Oregon Sports Authority	5,000
20	Redmond Economic Development, Inc.	7,000
21	Salt Lake Chamber	30,000
22	South Coast Development Council, Inc.	5,000
23	South Valley Chamber	5,000
24	Southern Oregon Regional Economic Development, Inc	7,500
25	Utah Manufacturers Association	10,471
26	Utah Taxpayers Association	18,700
27	Utah Technology Council	8,750
28	Utah Valley Chamber of Commerce	6,500
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)	137,596
33		
34	Rating Agency and Trustee Fees:	
35	The Bank of New York Mellon	127,965
36	Computershare Shareowner Services, LLC	17,857
37	Moody's Investors Service	121,854
38	Standard and Poor's Financial Services, LLC	198,940
39	U.S. Bank National Association	13,624
40	Other (Individually < $5,000)	1,035
41		
42	Directors' Fees - Regional Advisory Board	18,872
43		
44	General - Other	20
45		
46	TOTAL	2,244,072

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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			48,671,914		48,671,914
2	Steam Production Plant	277,542,946				277,542,946
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	38,319,142		311,696		38,630,838
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	247,234,128				247,234,128
7	Transmission Plant	112,507,659				112,507,659
8	Distribution Plant	161,981,289				161,981,289
9	Regional Transmission and Market Operation					
10	General Plant	42,404,362		706,273		43,110,635
11	Common Plant-Electric					
12	TOTAL	879,989,526		49,689,883		929,679,409

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 2019/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	WIND GENERATION						
14	Foote Creek						
15	340.20 All States	5,526			3.20		
16							
17							
18	Acct 403 - Provisions						
19							
20							
21							
22							
23							
24							
25							
26							
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50							

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, 2019, depreciation expense associated with transportation equipment was $16,386,376.

Schedule Page: 336 Line No.: 12 Column: e

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

Schedule Page: 336 Line No.: 12 Column: a

The 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 14 of Notes to Financial Statements in this Form No. 1.

Account No. (a)	Depreciable Plant Base ($000s) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
HYDRAULIC PRODUCTION						
Klamath River Accelerated						
330.20 CA/OR	$ 41					-
330.40 CA/OR	1					-
331.00 CA/OR	16,990					-
332.00 CA/OR	39,624					-
333.00 CA/OR	18,254					-
334.00 CA/OR	16,630					-
335.00 CA/OR	182					-
336.00 CA/OR	2,753					-
Total	$ 94,475			12.77		

Schedule Page: 336 Line No.: 18 Column: a

For a discussion on provisions for depreciation that were made during the year, refer to Note 3 of Notes to the 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 2019/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	6,244,201		6,244,201	
3	Rate Cases and Proceedings		267,955	267,955	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	3,374,491		3,374,491	
7	Rate Cases and Proceedings		782,606	782,606	
8	Deferred Intervenor Funding Grants				926,951
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,752,156		1,752,156	
12	Rate Cases and Proceedings		144,671	144,671	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	627,091		627,091	
17	Rate Cases and Proceedings		410,854	410,854	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	683,750		683,750	
21	Rate Cases and Proceedings		90,230	90,230	
22	Deferred Intervenor Funding Grants				66,865
23					
24	California Public Utilities Commission:				
25	Annual Fee	1,439		1,439	
26	Rate Cases and Proceedings		650,752	650,752	
27	Deferred Intervenor Funding Grants				41,995
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	70,935	8,012	78,947	
31					
32	Multi-State:				
33	Rate Cases and Proceedings		315,890	315,890	
34	Other Regulatory		1,571,261	1,571,261	
35					
36	Federal Energy Regulatory Commission:				
37	Annual Fee	2,468,009		2,468,009	
38	Annual Fee - Hydroelectric Plants	2,658,529		2,658,529	
39	Transmission Rate Cases		245,707	245,707	
40	Other Regulatory		3,237,297	3,237,297	
41					
42					
43					
44					
45					
46	TOTAL	17,880,601	7,725,235	25,605,836	1,035,811

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	6,244,201					2
Electric	928	267,955					3
							4
							5
Electric	928	3,374,491					6
Electric	928	782,606					7
			569,849			1,496,800	8
							9
							10
Electric	928	1,752,156					11
Electric	928	144,671					12
							13
							14
							15
Electric	928	627,091					16
Electric	928	410,854					17
							18
							19
Electric	928	683,750					20
Electric	928	90,230					21
						66,865	22
							23
							24
Electric	928	1,439					25
Electric	928	650,752					26
			1,754			43,749	27
							28
							29
Electric	928	78,947					30
							31
							32
Electric	928	315,890					33
Electric	928	1,571,261					34
							35
							36
Electric	928	2,468,009					37
Electric	928	2,658,529					38
Electric	928	245,707					39
Electric	928	3,237,297					40
							41
							42
							43
							44
							45
		25,605,836	571,603			1,607,414	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 2019/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	(6) Other	WestSmart Electric Vehicle Project
3	(6) Other	Utah Sustainable Transportation and Energy Plan
4		
5		
6		
7		
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38		

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)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
80,399			80,399		2
305,348	2,688,430	107,908	2,993,778		3
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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.: 2 Column: e

Account 557, Other expenses
Account 560, Operation supervision and engineering
Account 908, Customer assistance expenses

Schedule Page: 352 Line No.: 3 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	98,500,178		
4	Transmission	15,242,556		
5	Regional Market			
6	Distribution	36,832,966		
7	Customer Accounts	32,939,624		
8	Customer Service and Informational	7,320,919		
9	Sales			
10	Administrative and General	41,187,581		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	232,023,824		
12	Maintenance			
13	Production	45,001,166		
14	Transmission	11,616,988		
15	Regional Market			
16	Distribution	71,750,912		
17	Administrative and General	1,608,102		
18	TOTAL Maintenance (Total of lines 13 thru 17)	129,977,168		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	143,501,344		
21	Transmission (Enter Total of lines 4 and 14)	26,859,544		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	108,583,878		
24	Customer Accounts (Transcribe from line 7)	32,939,624		
25	Customer Service and Informational (Transcribe from line 8)	7,320,919		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	42,795,683		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	362,000,992		362,000,992
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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)	362,000,992		362,000,992
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	163,070,510		163,070,510
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	163,070,510		163,070,510
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,955,796		9,955,796
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,955,796		9,955,796
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	5,959,817		5,959,817
79	Miscellaneous Other Income Deductions	514,397		514,397
80	Miscellaneous Non-Operating and Non-Utility	912,471		912,471
81	Charges to Affiliates	698,114		698,114
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	8,084,799		8,084,799
96	TOTAL SALARIES AND WAGES	543,112,097		543,112,097

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)	347,365	362,023	2,553,768	2,663,242
3	Net Sales (Account 447)	(74,013)	(103,837)	(131,342)	(131,343)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Energy Imbalance Market (Account 555)	(32,890,418)	(6,951,983)	(14,615,028)	(38,601,478)
8					
9					
10					
11					
12					
13					
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44					
45					
46	TOTAL	(32,617,066)	(6,693,797)	(12,192,602)	(36,069,579)

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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year: Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year: Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				135,632,339	MWh	12,048,930
2	Reactive Supply and Voltage	114,577,957	MWh	7,287,885	129,422,935	MWh	8,271,361
3	Regulation and Frequency Response	54,981,585	MWh	33,972,358	74,862,218	MWh	41,056,109
4	Energy Imbalance				-1,025,172	MWh	18,597,634
5	Operating Reserve - Spinning	118,724,932	MWh	17,927,465	131,202,978	MWh	19,781,151
6	Operating Reserve - Supplement	118,724,932	MWh	17,927,465	131,691,201	MWh	19,854,873
7	Other						
8	Total (Lines 1 thru 7)	407,009,406		77,115,173	601,786,499		119,610,058

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	15,766	2	900	8,470	594	3,544		1,816	1,342
2	February	15,975	7	800	8,790	562	3,544		1,760	1,319
3	March	15,479	4	800	8,410	562	3,544		1,828	1,135
4	Total for Quarter 1				25,670	1,718	10,632		5,404	3,796
5	April	13,308	10	800	7,363	384	3,570		921	1,070
6	May	13,862	13	1800	7,496	338	3,570		1,287	1,171
7	June	16,237	28	1800	8,878	407	3,701		1,705	1,546
8	Total for Quarter 2				23,737	1,129	10,841		3,913	3,787
9	July	18,270	22	1700	10,436	471	3,701		1,849	1,813
10	August	18,278	5	1700	10,314	431	3,701		2,024	1,808
11	September	17,498	5	1700	9,901	409	3,701		1,759	1,728
12	Total for Quarter 3				30,651	1,311	11,103		5,632	5,349
13	October	15,553	30	800	8,465	557	3,709		1,556	1,266
14	November	15,581	26	1800	8,316	481	3,629		1,885	1,270
15	December	15,536	17	1800	8,734	511	3,629		1,311	1,351
16	Total for Quarter 4				25,515	1,549	10,967		4,752	3,887
17	Total Year to Date/Year				105,573	5,707	43,543		19,701	16,819

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
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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 2019 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 2019 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 2019 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.

FOOTNOTE DATA

Schedule Page: 400 Line No.: 17 Column: i

Year-to-date 2019 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 2019 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 2019/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)	55,342,607
3	Steam	38,283,488			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	302,600
5	Hydro-Conventional	2,839,382			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,177,028
7	Other	10,626,462			
8	Less Energy for Pumping	2,155	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	51,747,177	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	125,044
10	Purchases	12,097,791	27	Total Energy Losses	3,636,763
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	64,584,042
12	Received	7,707,795			
13	Delivered	6,826,841			
14	Net Exchanges (Line 12 minus line 13)	880,954			
15	Transmission For Other (Wheeling)				
16	Received	15,241,847			
17	Delivered	15,129,193			
18	Net Transmission for Other (Line 16 minus line 17)	112,654			
19	Transmission By Others Losses	-254,534			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	64,584,042			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	6,116,979	839,278	8,269	2	1800 PST
30	February	5,452,600	538,253	8,604	7	0800 PST
31	March	5,303,501	435,285	8,218	4	0800 PST
32	April	4,734,818	397,398	7,167	10	0800 PDT
33	May	4,786,585	253,950	7,311	13	1800 PDT
34	June	5,062,773	255,956	8,747	12	1700 PDT
35	July	5,883,677	218,029	10,334	22	1700 PDT
36	August	5,797,896	177,393	10,220	5	1700 PDT
37	September	5,165,778	397,374	9,722	5	1700 PDT
38	October	5,230,095	525,643	8,274	30	0800 PDT
39	November	5,297,562	613,690	8,081	26	1800 PST
40	December	5,751,778	524,779	8,498	17	1800 PST
41	TOTAL	64,584,042	5,177,028			

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 2019/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)	374			162		
7	Plant Hours Connected to Load	5312			8603		
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	1482932000			1082820000		
13	Cost of Plant: Land and Land Rights	2635317			1788644		
14	Structures and Improvements	65595551			67676397		
15	Equipment Costs	484419888			171025121		
16	Asset Retirement Costs	22278622			8277641		
17	Total Cost	574929378			248767803		
18	Cost per KW of Installed Capacity (line 17/5) Including	1388.7183			1598.6621		
19	Production Expenses: Oper, Supv, & Engr	2307136			30468		
20	Fuel	41486521			17091647		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	6114697			986660		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	309411			51410		
26	Misc Steam (or Nuclear) Power Expenses	2052900			1906865		
27	Rents	0			10042		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	2359677			253117		
30	Maintenance of Structures	4086250			389393		
31	Maintenance of Boiler (or reactor) Plant	4854765			2564639		
32	Maintenance of Electric Plant	1055833			8127		
33	Maintenance of Misc Steam (or Nuclear) Plant	1277890			344140		
34	Total Production Expenses	65905080			23636508		
35	Expenses per Net KWh	0.0444			0.0218		
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	874610	5588	0	665474	1383	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9189	129293	0	8385	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	44.008	96.105	0.000	23.976	96.428	0.000
41	Average Cost of Fuel per Unit Burned	46.820	96.105	0.000	25.483	96.428	0.000
42	Average Cost of Fuel Burned per Million BTU	2.548	17.698	2.576	1.519	16.399	1.530
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.028	0.016	0.000	0.016
44	Average BTU per KWh Net Generation	10839.206	20.463	10859.669	10306.855	7.511	10314.366

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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
161	752	78	6
8727	8760	8760	7
0	0	0	8
161	745	77	9
0	0	0	10
0	195	0	11
1166870000	4686381000	486469000	12
137086	10448598	683069	13
38554855	166341191	17797217	14
185278568	887464165	96325444	15
35149	29368123	2122487	16
224005658	1093622077	116928217	17
1301.3749	1338.9597	1436.9942	18
422593	15843	145370	19
23520484	49807479	12051841	20
0	0	0	21
2037591	2024824	1179420	22
0	0	0	23
0	0	0	24
808542	0	393609	25
1112827	16810355	492771	26
0	86157	0	27
0	0	0	28
792998	0	210597	29
564248	4307318	319054	30
3715128	14838235	689291	31
604437	11731602	208446	32
884870	1386180	216206	33
34463718	101007993	15906605	34
0.0295	0.0216	0.0327	35

Craig (d) Coal	Craig (d) Oil	Craig (d) Composite	Dave Johnston (e) Coal	Dave Johnston (e) Oil	Dave Johnston (e) Composite	Hayden (f) Coal	Hayden (f) Oil	Hayden (f) Composite	Line No.
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
609767	105	0	3184801	13963	0	239090	145	0	38
9689	133056	0	8212	138000	0	11294	136306	0	39
32.017	101.821	0.000	15.171	94.695	0.000	46.271	99.983	0.000	40
38.445	101.821	0.000	15.224	94.695	0.000	50.277	99.983	0.000	41
1.984	18.223	1.990	0.927	16.338	0.951	2.226	17.467	2.231	42
0.020	0.000	0.020	0.010	0.000	0.010	0.025	0.000	0.025	43
10126.513	0.504	10127.017	11161.565	17.269	11178.834	11101.555	1.702	11103.257	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Hunter Unit No. 1* (b)			Plant Name: *Hunter Unit No. 2* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler			Outdoor Boiler		
3	Year Originally Constructed	1978			1980		
4	Year Last Unit was Installed	1978			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	457.73			294.46		
6	Net Peak Demand on Plant - MW (60 minutes)	416			270		
7	Plant Hours Connected to Load	8756			8760		
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	2754327000			1802519000		
13	Cost of Plant: Land and Land Rights	9688261			9688261		
14	Structures and Improvements	65040176			54482308		
15	Equipment Costs	388792796			250955259		
16	Asset Retirement Costs	4278309			4278309		
17	Total Cost	467799542			319404137		
18	Cost per KW of Installed Capacity (line 17/5) Including	1021.9989			1084.7115		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	50679932			32508552		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	8268308			6256877		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	-60931			85963		
26	Misc Steam (or Nuclear) Power Expenses	2914656			-6351823		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	889773			1413135		
31	Maintenance of Boiler (or reactor) Plant	2540716			9633161		
32	Maintenance of Electric Plant	749579			3595083		
33	Maintenance of Misc Steam (or Nuclear) Plant	332077			385252		
34	Total Production Expenses	66314110			47526200		
35	Expenses per Net KWh	0.0241			0.0264		
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	1269491	2259	0	813081	1720	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11390	138000	0	11589	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	39.742	0.000	0.000	39.766	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.745	17.415	1.752	1.716	17.648	1.724
43	Average Cost of Fuel Burned per KWh Net Gen	0.018	0.000	0.018	0.018	0.000	0.018
44	Average BTU per KWh Net Generation	10499.604	4.753	10504.357	10455.414	5.531	10460.945

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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
474			1356			910			6
8481			7840			8328			7
0			0			0			8
471			1158			909			9
0			0			0			10
0			208			160			11
2883126000			7439972000			4897541000			12
10274569			29651091			2377564			13
93063053			212585537			127544191			14
447664189			1087412244			762757587			15
4278309			12834927			10022886			16
555280120			1342483799			902702228			17
1120.4425			1075.8978			906.3275			18
0			0			15087			19
52826299			136014783			104571495			20
0			0			0			21
8989022			23514207			13205769			22
0			0			0			23
0			0			0			24
-57347			-32315			0			25
3807812			370645			9848321			26
0			0			25964			27
0			0			0			28
0			0			1598911			29
1109881			3412789			2477961			30
4556362			16730239			13595055			31
685322			5029984			7992089			32
532779			1250108			822980			33
72450130			186290440			154153632			34
0.0251			0.0250			0.0315			35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
1299243	10943	0	3381815	14922	0	2219115	6142	0	38
11230	138000	0	11376	138000	0	11482	138000	0	39
0.000	0.000	0.000	39.356	99.812	0.000	45.293	97.754	0.000	40
39.824	0.000	0.000	39.779	99.812	0.000	46.852	97.754	0.000	41
1.773	17.114	1.806	1.748	17.221	1.766	2.040	16.866	2.051	42
0.018	0.000	0.018	0.018	0.000	0.018	0.021	0.000	0.021	43
10121.250	21.999	10143.249	10342.279	11.625	10353.904	10404.729	7.269	10411.998	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)			1417			649
7	Plant Hours Connected to Load			8760			8760
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			1415			384
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			329			112
12	Net Generation, Exclusive of Plant Use - KWh			9012300000			2840374000
13	Cost of Plant: Land and Land Rights			1193761			1321031
14	Structures and Improvements			148774873			127175501
15	Equipment Costs			1274734660			617520729
16	Asset Retirement Costs			19566856			50914765
17	Total Cost			1444270150			796932026
18	Cost per KW of Installed Capacity (line 17/5) Including			931.3966			1126.8835
19	Production Expenses: Oper, Supv, & Engr			14234340			299356
20	Fuel			252682285			86682877
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			19568003			7913360
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			1865
26	Misc Steam (or Nuclear) Power Expenses			-21036522			6252984
27	Rents			331946			14350
28	Allowances			0			0
29	Maintenance Supervision and Engineering			580006			1498176
30	Maintenance of Structures			10304164			1031530
31	Maintenance of Boiler (or reactor) Plant			23037622			4834856
32	Maintenance of Electric Plant			7389583			2952761
33	Maintenance of Misc Steam (or Nuclear) Plant			2295209			826583
34	Total Production Expenses			309386636			112308698
35	Expenses per Net KWh			0.0343			0.0395
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	5088688	10059	0	1540808	294181	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9336	138000	0	9965	1056	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	45.191	95.461	0.000	54.265	3.495	0.000
41	Average Cost of Fuel per Unit Burned	49.467	95.461	0.000	55.591	3.495	0.000
42	Average Cost of Fuel Burned per Million BTU	2.649	16.470	2.658	2.789	3.310	2.795
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.028	0.030	0.000	0.030
44	Average BTU per KWh Net Generation	10543.205	6.469	10549.674	10811.227	109.357	10920.584

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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
		289.66			251.64			279.56	5
		270			177			251	6
		7610			2294			7617	7
		0			0			0	8
		266			238			231	9
		0			0			0	10
		62			32			0	11
		1417217000			114952000			1511532000	12
		210526			1252090			796929	13
		52526739			15311112			12840581	14
		411039819			68474405			165639028	15
		279518			1132809			407646	16
		464056602			86170416			179684184	17
		1602.0735			342.4353			642.7392	18
		9495			34410			0	19
		22490477			6669026			29285582	20
		0			0			0	21
		3295495			144257			0	22
		0			0			0	23
		0			0			0	24
		0			0			7137888	25
		3800445			3691399			0	26
		15043			0			0	27
		0			0			0	28
		0			0			0	29
		240210			128946			0	30
		2978981			906130			0	31
		1175767			1166287			0	32
		134621			445065			0	33
		34140534			13185520			36423470	34
		0.0241			0.1147			0.0241	35
Coal	Oil	Composite	Gas			Gas			36
Tons	Barrels		MCF			MCF			37
1150788	4566	0	1913753	0	0	10809997	0	0	38
8096	138000	0	1053	0	0	1046	0	0	39
18.976	88.926	0.000	3.485	0.000	0.000	2.709	0.000	0.000	40
19.191	88.926	0.000	3.485	0.000	0.000	2.709	0.000	0.000	41
1.185	15.343	1.205	3.309	0.000	0.000	2.590	0.000	0.000	42
0.016	0.000	0.016	0.058	0.000	0.000	0.019	0.000	0.000	43
13147.486	18.675	13166.161	17530.143	0.000	0.000	7481.695	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)	20	507
7	Plant Hours Connected to Load	8588	6694
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	20	18
12	Net Generation, Exclusive of Plant Use - KWh	115179000	2431536000
13	Cost of Plant: Land and Land Rights	41195596	3730527
14	Structures and Improvements	8435435	24460904
15	Equipment Costs	103009122	328898079
16	Asset Retirement Costs	2272415	1030777
17	Total Cost	154912568	358120287
18	Cost per KW of Installed Capacity (line 17/5) Including	4065.9467	603.6074
19	Production Expenses: Oper, Supv, & Engr	43503	192912
20	Fuel	0	64982881
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	265042	0
23	Steam From Other Sources	4836772	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	1934664
26	Misc Steam (or Nuclear) Power Expenses	1739757	878661
27	Rents	8964	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	352874	28915
31	Maintenance of Boiler (or reactor) Plant	294801	0
32	Maintenance of Electric Plant	194104	1693967
33	Maintenance of Misc Steam (or Nuclear) Plant	47548	0
34	Total Production Expenses	7783365	69712000
35	Expenses per Net KWh	0.0676	0.0287

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				MCF		
38	Quantity (Units) of Fuel Burned	0	0	0	16292784	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1102	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	3.988	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	3.988	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	3.621	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.027	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	7380.752	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
120			561			518			6
571			8654			8193			7
0			0			0			8
119			524			546			9
0			0			0			10
0			20			31			11
19230000			2917279000			2781914000			12
0			3403277			14532275			13
4263755			44247448			35509220			14
81328508			307259168			339055599			15
0			134848			0			16
85592263			355044741			389097094			17
472.7548			626.2917			658.0367			18
0			60872			47328			19
1160580			64056541			64738243			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
734954			1747075			2341763			25
0			1021373			496509			26
0			0			0			27
0			0			0			28
0			0			0			29
58078			420484			909310			30
0			0			0			31
307244			920033			1256397			32
123631			68252			14715			33
2384487			68294630			69804265			34
0.1240			0.0234			0.0251			35
Gas			Gas			Gas			36
MCF			MCF			MCF			37
244619	0	0	20700822	0	0	20079834	0	0	38
1057	0	0	1042	0	0	1045	0	0	39
4.744	0.000	0.000	3.094	0.000	0.000	3.224	0.000	0.000	40
4.744	0.000	0.000	3.094	0.000	0.000	3.224	0.000	0.000	41
4.489	0.000	0.000	2.969	0.000	0.000	3.085	0.000	0.000	42
0.060	0.000	0.000	0.022	0.000	0.000	0.023	0.000	0.000	43
13443.474	0.000	0.000	7395.894	0.000	0.000	7542.521	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 2019/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)	626	0
7	Plant Hours Connected to Load	6230	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	2281902000	0
13	Cost of Plant: Land and Land Rights	16794626	0
14	Structures and Improvements	53128704	0
15	Equipment Costs	569331831	0
16	Asset Retirement Costs	0	0
17	Total Cost	639255161	0
18	Cost per KW of Installed Capacity (line 17/5) Including	975.6642	0
19	Production Expenses: Oper, Supv, & Engr	54696	0
20	Fuel	55984255	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	3127779	0
26	Misc Steam (or Nuclear) Power Expenses	574681	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	957626	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	378560	0
33	Maintenance of Misc Steam (or Nuclear) Plant	15451	0
34	Total Production Expenses	61093048	0
35	Expenses per Net KWh	0.0268	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	16958632	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1044	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.301	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.301	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.162	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	7758.462	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.

In December 2019, PacifiCorp initiated steps toward retiring Cholla Unit No. 4 by December 31, 2020.

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 2019 were $1.2 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 2019 were $11.8 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 2019 were $30.9 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) was removed from service as a coal-fueled generating unit and will be converted to a natural gas-fueled generation resource that is expected to be completed, including all required regulatory notices and filings, by the end of 2020.

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 2019 were $3.9 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 Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: c2
Colstrip Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: d2
Craig Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: e2
Dave Johnston Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: f2
Hayden Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: b2
Hunter Plant, Unit No. 1 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: c2
Hunter Plant, Unit No. 2 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: d2
Hunter Plant, 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 Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: b2
Jim Bridger Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: d2
Wyodak Plant - 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 2019/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. 14803 Plant Name: Copco No. 1 (b)	FERC Licensed Project No. 14803 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	5,648	5,677
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	85,841,000	108,585,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	2,106,958	2,556,192
16	Reservoirs, Dams, and Waterways	3,374,971	3,134,323
17	Equipment Costs	5,713,067	10,514,919
18	Roads, Railroads, and Bridges	133,348	551,687
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	11,435,363	16,778,035
21	Cost per KW of Installed Capacity (line 20 / 5)	571.7682	621.4087
22	Production Expenses		
23	Operation Supervision and Engineering	21,216	28,641
24	Water for Power	0	0
25	Hydraulic Expenses	1,048	1,414
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	1,077,576	1,243,258
28	Rents	120,695	162,938
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	2,787	3,395
31	Maintenance of Reservoirs, Dams, and Waterways	12,324	898
32	Maintenance of Electric Plant	101,694	6,866
33	Maintenance of Misc Hydraulic Plant	15,425	20,823
34	Total Production Expenses (total 23 thru 33)	1,352,765	1,468,233
35	Expenses per net KWh	0.0158	0.0135

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
9	16	29	6
6,725	8,548	7,293	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
26,356,000	35,821,000	90,186,000	12
			13
0	0	3,511,105	14
1,500,707	2,442,850	4,712,789	15
5,185,834	14,820,860	10,043,511	16
1,407,764	2,198,202	15,038,961	17
50,817	250,151	590,232	18
0	0	0	19
8,145,122	19,712,063	33,896,598	20
543.0081	758.1563	1,129.8866	21
			22
21,753	29,046	129,376	23
338	586	0	24
34,567	59,916	114,728	25
0	0	0	26
326,338	456,212	1,428,546	27
62,093	107,628	18,011	28
0	0	0	29
21,528	37,586	0	30
7,297	10,946	5,682	31
54,360	7,042	16,407	32
72,409	125,599	334,104	33
600,683	834,561	2,046,854	34
0.0228	0.0233	0.0227	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 2019/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	28
7	Plant Hours Connect to Load	2,657	8,471
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	5
12	Net Generation, Exclusive of Plant Use - Kwh	20,911,000	80,378,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	1,764,935	2,959,781
16	Reservoirs, Dams, and Waterways	12,462,362	13,006,415
17	Equipment Costs	2,993,343	5,845,562
18	Roads, Railroads, and Bridges	533,015	546,915
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,753,655	22,420,842
21	Cost per KW of Installed Capacity (line 20 / 5)	1,613.9686	679.4195
22	Production Expenses		
23	Operation Supervision and Engineering	12,289	125,312
24	Water for Power	248	0
25	Hydraulic Expenses	25,349	37,655
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	261,016	1,567,742
28	Rents	45,535	12,477
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	16,389	17,856
31	Maintenance of Reservoirs, Dams, and Waterways	5,999	91,128
32	Maintenance of Electric Plant	4,474	124,958
33	Maintenance of Misc Hydraulic Plant	53,100	86,818
34	Total Production Expenses (total 23 thru 33)	424,399	2,063,946
35	Expenses per net KWh	0.0203	0.0257

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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. 14803 Plant Name: Iron Gate (d)	FERC Licensed Project No. 14803 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	76	30	6
8,471	6,294	8,298	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
101,368,000	228,036,000	114,477,000	12
			13
341,617	25,845	0	14
8,516,810	3,807,630	2,940,391	15
17,215,786	15,898,657	15,807,139	16
3,206,406	15,631,472	6,726,791	17
1,095,742	972,360	484,046	18
0	0	0	19
30,376,361	36,335,964	25,958,367	20
1,687.5756	370.8508	811.4525	21
			22
1,310,374	166,463	35,738	23
0	0	721	24
943	4,979	73,720	25
0	0	0	26
1,072,544	1,023,745	710,190	27
108,626	2,305	132,424	28
0	0	0	29
3,282	88,225	77,412	30
8,566	23,609	6,840	31
120,412	214,540	70,001	32
13,882	131,211	155,188	33
2,638,629	1,655,077	1,262,234	34
0.0260	0.0073	0.0110	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 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Lemolo No. 2 (b)	FERC Licensed Project No. 935 Plant Name: Merwin (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage (Re-Reg)
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1956	1931
4	Year Last Unit was Installed	1956	1958
5	Total installed cap (Gen name plate Rating in MW)	38.50	136.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	33	140
7	Plant Hours Connect to Load	8,711	8,760
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	143,451,000	337,034,000
13	Cost of Plant		
14	Land and Land Rights	0	1,735,054
15	Structures and Improvements	6,296,317	111,143,662
16	Reservoirs, Dams, and Waterways	32,880,312	31,885,493
17	Equipment Costs	11,847,627	18,947,937
18	Roads, Railroads, and Bridges	1,820,580	4,135,655
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	52,844,836	167,847,801
21	Cost per KW of Installed Capacity (line 20 / 5)	1,372.5931	1,234.1750
22	Production Expenses		
23	Operation Supervision and Engineering	43,011	1,689,541
24	Water for Power	868	3,618
25	Hydraulic Expenses	88,722	788,143
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	643,546	562,242
28	Rents	159,372	96,619
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	56,821	36,479
31	Maintenance of Reservoirs, Dams, and Waterways	152,722	32,091
32	Maintenance of Electric Plant	15,261	137,630
33	Maintenance of Misc Hydraulic Plant	185,851	500,907
34	Total Production Expenses (total 23 thru 33)	1,346,174	3,847,270
35	Expenses per net KWh	0.0094	0.0114

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1927 Plant Name: Toketee (d)	FERC Licensed Project No. 20 Plant Name: Oneida (e)	FERC Licensed Project No. 2630 Plant Name: Prospect No. 2 (f)	Line No.
Storage	Storage	Run-of-River	1
Conventional	Conventional	Conventional	2
1949	1915	1928	3
1950	1920	1928	4
42.50	30.00	32.00	5
43	17	36	6
8,555	8,759	8,656	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
193,356,000	51,274,000	190,315,000	12
			13
0	283,870	105,168	14
4,381,649	2,319,787	4,238,499	15
12,846,444	8,536,133	35,368,390	16
6,271,807	15,673,315	7,376,960	17
502,952	662,757	533,423	18
0	0	0	19
24,002,852	27,475,862	47,622,440	20
564.7730	915.8621	1,488.2013	21
			22
71,088	90,472	394,402	23
958	0	12,490	24
97,942	34,232	1,626	25
0	0	0	26
736,778	849,267	712,142	27
175,933	10,751	40,113	28
0	0	260	29
67,843	0	64,842	30
12,989	7,436	200,591	31
117,837	77,027	99,617	32
205,165	57,958	438,020	33
1,486,533	1,127,143	1,964,103	34
0.0077	0.0220	0.0103	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 2019/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)	15	7
7	Plant Hours Connect to Load	7,857	7,697
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	46,271,000	20,509,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	2,205,575	1,325,982
16	Reservoirs, Dams, and Waterways	14,883,968	11,107,798
17	Equipment Costs	8,978,518	5,446,933
18	Roads, Railroads, and Bridges	582,653	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	26,650,714	18,391,796
21	Cost per KW of Installed Capacity (line 20 / 5)	1,480.5952	1,272.7887
22	Production Expenses		
23	Operation Supervision and Engineering	24,905	42,220
24	Water for Power	406	0
25	Hydraulic Expenses	41,480	15,975
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	351,691	466,712
28	Rents	74,512	5,077
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	28,288	60
31	Maintenance of Reservoirs, Dams, and Waterways	20,519	3,591
32	Maintenance of Electric Plant	89,618	30,637
33	Maintenance of Misc Hydraulic Plant	86,891	27,047
34	Total Production Expenses (total 23 thru 33)	718,310	591,319
35	Expenses per net KWh	0.0155	0.0288

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	243	164	6
7,863	4,399	5,291	7
			8
12	264	164	9
12	264	164	10
2	1	1	11
38,101,000	369,084,000	370,023,000	12
			13
0	17,912,070	8,363,013	14
4,306,658	71,477,347	17,641,394	15
90,257,199	48,366,872	35,024,807	16
2,624,544	25,269,498	18,290,672	17
2,089,012	1,319,865	2,045,631	18
0	0	0	19
99,277,413	164,345,652	81,365,517	20
9,025.2194	684.7736	607.2054	21
			22
12,289	2,948,946	1,576,354	23
248	6,384	3,564	24
112,090	1,636,070	776,553	25
0	0	0	26
435,622	404,476	486,488	27
45,535	170,475	95,182	28
0	0	0	29
16,506	32,253	24,888	30
87,988	114,965	75,687	31
105,167	175,100	84,677	32
61,413	854,965	478,730	33
876,858	6,343,634	3,602,123	34
0.0230	0.0172	0.0097	35

Schedule Page: 406 Line No.: -1 Column: b

This footnote applies to all hydroelectric generating facilities with current generation. All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406 Line No.: 1 Column: b

Copco No. 1 - Pondage for peaking - storage, Upper Klamath Lake

Schedule Page: 406 Line No.: 1 Column: d

Clearwater No. 1 - Forebay for peaking

Schedule Page: 406 Line No.: 1 Column: e

Clearwater No. 2 - Forebay for peaking

Schedule Page: 406.1 Line No.: 1 Column: b

Fish Creek - Forebay for peaking

Schedule Page: 406.1 Line No.: 1 Column: d

Iron Gate - Storage for regulation

Schedule Page: 406.1 Line No.: 1 Column: e

JC Boyle - Pondage for peaking - storage, Upper Klamath Lake

Schedule Page: 406.1 Line No.: 1 Column: f

Lemolo No. 1 - Storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: b

Lemolo No. 2 - Storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: d

Toketee - Pondage for peaking - storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: f

Prospect No. 2 - Forebay for peaking

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydroelectric: Licensed Proj. No.					
2	Ashton 2381	1917	6.85	7.0	39,649,000	34,004,801
3	Bend	1913	1.11	1.0	1,559,000	2,515,771
4	Big Fork 2652	1910	4.15	4.6	27,204,000	9,678,829
5	Eagle Point	1957	2.81	2.8	16,812,000	2,011,617
6	East Side 2082	1924	3.20			1,991,695
7	Fall Creek 2082	1903	2.20	2.0	6,046,000	2,138,474
8	Granite	1896	2.00	1.2	6,719,000	5,261,269
9	Gunlock	1917	0.75	0.5	1,782,000	683,045
10	Last Chance	1983	1.73	1.4	4,695,000	3,176,847
11	Paris 703	1910	0.72	0.7	2,489,000	459,978
12	Pioneer 2722	1897	5.00	4.0	21,353,000	11,654,674
13	Prospect No. 1 2630	1912	3.76	4.6	8,511,000	5,344,452
14	Prospect No. 3 2337	1932	7.20	7.0	23,624,000	9,256,486
15	Prospect No. 4 2630	1944	1.00	0.9	1,817,000	2,518,127
16	Sand Cove	1926	0.80	0.5	1,820,000	1,139,789
17	Stairs 597	1895	1.00	1.2	5,771,000	1,952,878
18	Veyo	1920	0.50	0.3	774,000	898,464
19	Viva Naughton	1986	0.74	0.1	590,000	1,232,115
20	Wallowa Falls 308	1921	1.10	1.1	2,745,000	3,796,648
21	Weber 1744	1911	3.85	2.0	14,064,000	3,892,817
22	West Side 2082	1908	0.60	1.0	-19,000	478,946
23	Keno Regulating Dam 2082					7,684,061
24	Upper Klamath Lake 2082					3,849,552
25	North Umpqua 1927					17,125,400
26						
27	Pumping Plant:					
28	Lifton	1917	-2.80	-2.0	-2,155,000	19,551,056
29						
30	Wind:					
31	Dunlap Ranch 1	2010	111.00	111.0	384,833,000	243,396,368
32	Foote Creek	1999	41.40	35.0	107,369,000	48,338,925
33	Glenrock	2008	99.00	100.0	276,714,000	190,998,327
34	Glenrock III	2009	39.00	39.0	106,250,000	80,657,757
35	Rolling Hills	2009	99.00	100.0	267,528,000	195,865,109
36	Goodnoe Hills	2008	94.00	90.0	47,965,000	157,081,152
37	Leaning Juniper 1	2006	100.50	100.0	98,159,000	176,413,273
38	Marengo	2007	140.40	120.0	143,441,000	246,917,949
39	Marengo II	2008	70.20	66.0	91,293,000	131,515,092
40	Seven Mile Hill	2008	99.00	99.0	320,975,000	187,112,396
41	Seven Mile Hill II	2008	19.50	19.5	64,968,000	38,261,389
42	High Plains	2009	99.00	99.0	235,562,000	190,134,438
43	McFadden Ridge I	2009	28.50	28.5	75,204,000	52,540,131
44						
45	Solar:					
46	Black Cap	2012	2.00	2.0	3,289,000	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 2019/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
5,075,343	454,176		149,232	Water		2
2,266,460	90,798		3,403	Water		3
2,332,248	323,530		113,408	Water		4
715,878	305,682		103,622	Water		5
622,405	33,683		66,449	Water		6
972,034	173,202		29,749	Water		7
2,630,635	197,363		11,865	Water		8
910,727	37,008		51,952	Water		9
1,836,328	113,004		13,325	Water		10
638,858	74,596		10,677	Water		11
2,330,935	411,057		81,454	Water		12
1,421,397	138,550		121,261	Water		13
1,285,623	334,353		171,900	Water		14
2,518,127	39,552		29,665	Water		15
1,424,736	46,935		83,633	Water		16
1,952,878	223,418		5,703	Water		17
1,796,928	39,917		332,212	Water		18
1,665,020	9,671		63,984	Water		19
3,451,498	315,587		41,479	Water		20
1,011,121	162,881		53,199	Water		21
798,243	8,372		70,879	Water		22
	14,160		8,223			23
	288,327		110,123			24
						25
						26
						27
-6,982,520	227,024		29,733	Water		28
						29
						30
2,192,760	367,926		1,190,706	Wind		31
1,167,607	1,192,666		1,250,631	Wind		32
1,929,276	191,664		740,767	Wind		33
2,068,148	78,135		382,682	Wind		34
1,978,435	192,248		1,247,565	Wind		35
1,671,076	958,589		484,223	Wind		36
1,755,356	1,133,720		272,243	Wind		37
1,758,675	737,176		893,869	Wind		38
1,873,434	465,922		445,604	Wind		39
1,890,024	791,847		551,715	Wind		40
1,962,123	54,683		105,554	Wind		41
1,920,550	1,014,346		814,274	Wind		42
1,843,513	290,190		289,526	Wind		43
						44
						45
37,493	487,066			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.: 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 included 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

In July 2019, PacifiCorp completed a transaction with Eugene Water & Electric Board to acquire the remaining undivided interest in the Foote Creek I joint-owned wind generating facility. For further discussion, refer to Item 12 in Important Changes During the Year in this Form No. 1.

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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/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								
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	1.00		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					1,212.00		12
16								
17	90TH SOUTH, UT	CAMP WILLIAMS #3, UT	345.00	345.00	Steel - SP	11.00		1
18	90TH SOUTH, UT	CAMP WILLIAMS #4, UT	345.00	345.00	Steel - SP		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	Steel - SP		16.00	1
21	BEN LOMOND, UT	POPULUS #1, ID	345.00	345.00	Steel - SP		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	Steel - SP	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	Steel Tower	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	16,965.00	651.00	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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
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	236,936,844	250,276,543	3,358	1,601,934	316,379	1,921,671	14
	13,339,699	236,936,844	250,276,543	3,358	1,601,934	316,379	1,921,671	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
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	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 2019/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	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	Steel - SP		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	Steel Tower		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	16,965.00	651.00	288

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 2019/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)	
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
	154,511,677	1,660,982,229	1,815,493,906	204,404	1,261,113	589,703	2,055,220	23
	154,511,677	1,660,982,229	1,815,493,906	204,404	1,261,113	589,703	2,055,220	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
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	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 2019/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	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	CORRAL, OR	OCHOCO #1, OR	230.00	230.00	Wood - H	9.00		1
8	CRAVEN CREEK, WY	PIONEER, WY	230.00	230.00	Wood - H	2.00		1
9	DAVE JOHNSTON, WY	SPENCE, WY	230.00	230.00	Wood - H	31.00		1
10	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
11	DIXONVILLE 500kV, OR	DIXONVILLE 230kV, OR	230.00	230.00	Wood - H	1.00		1
12	DIXONVILLE, OR	RESTON (BPA), OR	230.00	230.00	Wood - H	17.00		1
13	FAIRVIEW (BPA), OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
14	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	49.00		1
15	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
16	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
17	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
18	GONDER, UT-NV STATE	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
19	DIXONVILLE, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	62.00		1
20	HIGH PLAINS, WY	STANDPIPE, WY	230.00	230.00	Wood - H	38.00		1
21	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
22	JIM BRIDGER, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	35.00		1
23	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
24	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	36.00		1
25	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
26	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
27	LONE PINE, OR	MERIDIAN #1, OR	230.00	230.00	Steel - SP	5.00		1
28	LONE PINE, OR	MERIDIAN #2, OR	230.00	230.00	Steel - SP	5.00		1
29	MCNARY (BPA), OR	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
30	MCNARY (BPA), OR	WALLULA, WA	230.00	230.00	Wood - H	29.00		1
31	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
32	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
33	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
34	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
35	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
36					TOTAL	16,965.00	651.00	288

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 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 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
								7
1272 ACSR 45/7								8
1272 ACSR 45/7								9
1272 ACSR 36/1								10
1272 ACSR 36/1								11
795 ACSR 26/7								12
1272 ACSR 36/1								13
1272 ACSR 45/7								14
1272 ACSR 36/1								15
1272 ACSR 36/1								16
954 ACSR 45/7								17
795 ACSR 45/7								18
1272 ACSR 36/1								19
1272 ACSR 45/7								20
1272 ACSR 36/1								21
1272 ACSR 45/7								22
1272 ACSR 36/1								23
1272 ACSR 36/1								24
1272 ACSR 45/7								25
795 ACSR 26/7								26
1272 ACSR 54/19								27
1272 ACSR 36/1								28
1272 ACSR 36/1								29
								30
1272 ACSR 36/1								31
1272 ACSR 36/1								32
1272 ACSR 45/7								33
1272 ACSR 45/7								34
1272 ACSR 36/1								35
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	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 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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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	NAUGHTON, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	16.00		1
2	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
3	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
4	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
5	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
6	POINT OF ROCKS, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	209.00		1
7	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	7.00		1
8	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
9	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
10	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
11	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
12	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
13	SHERIDAN (MDU), WY	BUFFALO, WY	230.00	230.00	Wood - H	40.00		1
14	SHERIDAN (MDU), WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	62.00		1
15	SHIRLEY BASIN, WY	DUNLAP RANCH, WY	230.00	230.00	Wood - H	12.00		1
16	SWIFT NO. 1, WA	SWIFT NO. 2, WA	230.00	230.00	Wood - H	2.00		1
17	SWIFT NO. 2, WA	WOODLAND (BPA) SS, WA	230.00	230.00	Wood - H	23.00		1
18	TALBOT, WA	MARENGO II, WA	230.00	230.00	Wood - H	7.00		1
19	TAP TO HANNA, OR	NICKEL MOUNTAIN, OR	230.00	230.00	Wood - H	9.00		1
20	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
21	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
22	TROUTDALE (BPA), OR	GRESHAM (PGE), OR	230.00	230.00	Steel Tower	6.00		1
23	TROUTDALE (BPA), OR	LINNEMAN (PGE), OR	230.00	230.00	Steel Tower		7.00	1
24	UNION GAP, WA	MIDWAY (BPA), WA	230.00	230.00	Wood - H	39.00		1
25	WALLA WALLA, WA	LEWISTON (AVISTA), ID	230.00	230.00	Wood - H	45.00		1
26	WALLA WALLA, WA	WANAPUM (GPUD), WA	230.00	230.00	Wood - H	33.00		1
27	WANAPUM (GPUD), WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
28	WINDSTAR, WY	GLENROCK, WY	230.00	230.00	Wood - H	13.00		1
29	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
30	YAMSAY (BPA), OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
31	230kV costs and expenses							
32	Subtotal 230kV					3,376.00	13.00	75
33								
34								
35								
36					TOTAL	16,965.00	651.00	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR 54/7								1
1272 ACSR 36/1								2
795 ACSR 45/7								3
795 ACSR 45/7								4
795 ACSR 45/7								5
1272 ACSR 36/1								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
1272 ACSR 36/1								11
1272 ACSR 36/1								12
795 ACSR 26/7								13
795 ACSR 26/7								14
795 ACSR 26/7								15
954 ACSR 45/7								16
954 ACSR 45/7								17
795 ACSR 26/7								18
795 ACSR 26/7								19
1272 ACSR 36/1								20
795 ACSR 26/7								21
954 ACSR 45/7								22
900 ACSR 54/7								23
954 ACSR 45/7								24
1272 ACSR 36/1								25
1272 ACSR 36/1								26
1272 ACSR 36/1								27
1272 ACSR 45/7								28
1272 ACSR 36/1								29
795 ACSR 26/7								30
	25,159,753	434,223,527	459,383,280	81,331	2,896,518	424,374	3,402,223	31
	25,159,753	434,223,527	459,383,280	81,331	2,896,518	424,374	3,402,223	32
								33
								34
								35
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	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 2019/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	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
2	BIG GRASSY, ID	JEFFERSON, ID	161.00	161.00	Wood - H		21.00	1
3	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood - SP	9.00		1
4	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	15.00		1
5	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
6	GOSHEN, ID	JEFFERSON, ID	161.00	161.00	Wood - H		30.00	1
7	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
8	GOSHEN, ID	SUGAR MILL, ID	161.00	161.00	Wood - SP	17.00		1
9	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood - SP	18.00		1
10	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood - SP	17.00		1
11	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
12	161kV costs and expenses							
13	Subtotal 161kV					255.00	51.00	11
14								
15	90TH SOUTH, UT	DUMAS #1, UT	138.00	138.00	Wood - H	12.00		1
16	90TH SOUTH, UT	DUMAS #2, UT	138.00	138.00	Wood - H	6.00		1
17	90TH SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	10.00		1
18	90TH SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
19	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - H	44.00		1
20	ABAJO, UT	SAN JUAN, UT	138.00	138.00	Wood - SP	10.00		1
21	AGRIUM, UT	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
22	ANSCHTZ CO-GEN, WY	EVANSTON, WY	138.00	138.00	Wood - H	22.00		1
23	ANTELOPE, ID	SCOVILLE #1, ID	138.00	138.00	Wood - H	1.00		1
24	ANTELOPE, ID	SCOVILLE #2, ID	138.00	138.00	Wood - H	1.00		1
25	ASHGROVE, UT	CLOVER, UT	138.00	138.00	Wood - H	26.00		1
26	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	102.00		1
27	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
28	BANGERTER, UT	OQUIRRH, UT	138.00	138.00	Wood - H		6.00	1
29	BARNEYS, UT	GRINDING, UT	138.00	138.00	Wood - SP	1.00		1
30	BDO, UT	BDO TAP, UT	138.00	138.00	Wood - SP	1.00		1
31	BEN LOMOND, UT	ANGEL, UT	138.00	138.00	Steel - SP	27.00		1
32	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
33	BEN LOMOND #1, UT	EL MONTE, UT	138.00	138.00	Steel - SP	14.00		1
34	BEN LOMOND #2, UT	EL MONTE, UT	138.00	138.00	Wood - H		13.00	1
35	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00	Steel Tower	22.00		1
36					TOTAL	16,965.00	651.00	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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)	
397.5 ACSR 26/7								1
250HH CU /7								2
954 ACSR 45/7								3
1272 ACSR 45/7								4
250HH CU /7								5
250HH CU /7								6
397.5 ACSR 26/7								7
795 AAC /37								8
397.5 ACSR 26/7								9
397.5 ACSR 26/7								10
556.5 ACSR 26/7								11
	661,223	40,759,855	41,421,078	18,992	262,267	13,522	294,781	12
	661,223	40,759,855	41,421,078	18,992	262,267	13,522	294,781	13
								14
795 AAC /37								15
795 AAC /37								16
795 ACSR 26/7								17
795 AAC /37								18
397.5 ACSR 26/7								19
795 ACSR 26/7								20
397.5 ACSR 26/7								21
795 ACSR 26/7								22
397.5 ACSR 26/7								23
397.5 ACSR 26/7								24
397.5 ACSR 26/7								25
397.5 ACSR 26/7								26
397.5 ACSR 26/7								27
								28
1272 AAC /61								29
397.5 ACSR 26/7								30
397.5 ACSR 26/7								31
1272 ACSR 45/7								32
795 ACSR 45/7								33
795 ACSR 45/7								34
250 CUHD /12								35
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	36

TRANSMISSION LINE STATISTICS

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2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	BEN LOMOND, UT	SYRACUSE #1, UT	138.00	230.00	Steel Tower	7.00	13.00	1
2	BEN LOMOND, UT	SYRACUSE, UT	138.00	138.00	Steel Tower	58.00		1
3	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood - SP	14.00		1
4	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
5	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	9.00		1
6	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Wood - SP	16.00		1
7	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
8	BUTLERVILLE, UT	90TH SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
9	CAMERON, UT	MILFORD, UT	138.00	138.00	Wood - SP	25.00		1
10	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
11	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	65.00		1
12	CANYON COMP, WY	STR 204, WY	138.00	138.00	Wood - H	12.00		1
13	CARBON, UT	HELPER #2, UT	138.00	138.00	Wood - H	2.00		1
14	CARBON, UT	MOAB, UT	138.00	138.00	Wood - H	120.00		1
15	CARBON, UT	SPANISH FORK #1, UT	138.00	138.00	Steel Tower	54.00		1
16	CARBON, UT	SPANISH FORK #2, UT	138.00	138.00	Steel Tower	52.00		1
17	CENTRAL (UAMPS) #2, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP	20.00		1
18	CENTRAL (UAMPS) #3, UT	SAINT GEORGE, UT	138.00	138.00	Steel - SP		20.00	1
19	CLEAR CREEK, WY	PAINTER, UT	138.00	138.00	Wood - SP	5.00		1
20	CLOVER, UT	BURRASTON PONDS	138.00	138.00	Wood - SP	2.00		1
21	CLOVER, UT	NEBO, UT	138.00	138.00	Wood - SP	8.00		1
22	COLUMBIA, UT	SUNNYSIDE, UT	138.00	138.00	Wood - H	2.00		1
23	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood - SP	5.00		1
24	COTTONWOOD, UT	MCCLELLAND, UT	138.00	138.00	Steel - SP	6.00		1
25	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood - SP	30.00		1
26	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood - SP			1
27	DRY CREEK, UT	SPANISH FORK, UT	138.00	138.00	Steel - SP	5.00		1
28	DUMAS, UT	WESTFIELD, UT	138.00	138.00	Wood - SP	19.00		1
29	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
30	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00	Steel - SP		3.00	1
31	EAGLE MOUNTAIN, UT	PONY EXPRESS, UT	138.00	138.00	Wood - SP	10.00		1
32	EAST LAYTON, UT	105 TAP, UT	138.00	138.00	Steel - SP	15.00		1
33	EBAY TAP, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	1.00		1
34	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
35	EL MONTE, UT	EAST BANK, UT	138.00	138.00	Steel - SP	4.00		1
36					TOTAL	16,965.00	651.00	288

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TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 AAC /37								1
1272 ACSR 45/7								2
795 AAC /37								3
250 CUHD /12								4
795 ACSR 26/7								5
1272 ACSR 45/7								6
795 ACSR 26/7								7
795 AAC /37								8
397.5 ACSR 26/7								9
397.5 ACSR 26/7								10
397.5 ACSR 26/7								11
795 ACSR 26/7								12
556.5 ACSR 26/7								13
954 ACSR 54/7								14
795 ACSR 26/7								15
1272 ACSR 45/7								16
1272 ACSR 45/7								17
1272 ACSR 45/7								18
795 ACSR 26/7								19
397.5 ACSR 26/7								20
1272 ACSR 45/7								21
397.5 ACSR 26/7								22
795 AAC /37								23
795 AAC /37								24
397.5 ACSR 26/7								25
250 CUHD /12								26
1272 ACSR 45/7								27
795 ACSR 26/7								28
795 ACSR 26/7								29
795 ACSR 26/7								30
795 ACSR 26/7								31
795 ACSR 26/7								32
795 ACSR 26/7								33
1272 ACSR 45/7								34
1272 ACSR 45/7								35
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	36

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	EVANSTON, WY	RAILROAD, UT	138.00	138.00	Wood - SP	3.00		1
2	FORT DOUGLAS, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	3.00		1
3	FRANKLIN, ID	GREEN CANYON, UT	138.00	138.00	Wood - SP	25.00		1
4	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood - SP	10.00		1
5	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood - SP			1
6	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
7	GADSBY, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
8	GRAPHITE, UT	MOUNTAIN VIEW, UT	138.00	138.00	Wood - SP	1.00		1
9	GREEN CANYON, UT	NIBLEY, UT	138.00	138.00	Wood - SP	7.00		1
10	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood - SP	19.00		1
11	GRINDING, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	3.00		1
12	GRINDING, UT	TOOELE, UT	138.00	138.00	Wood - SP	14.00		1
13	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
14	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
15	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
16	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00	Wood - SP		2.00	1
17	HIGHLAND, UT	BULL RIVER (LEHI #5), UT	138.00	138.00	Wood - SP	5.00		1
18	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
19	HONEYVILLE, UT	WHEELON, UT	138.00	138.00	Steel Tower		14.00	1
20	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
21	JERUSALEM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
22	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	5.00		1
23	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
24	JORDAN, UT	THIRD WEST, UT	138.00	138.00	Wood - SP	1.00		1
25	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	3.00		1
26	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	2.00		1
27	LONE PEAK, UT	CAMP WILLIAMS, UT	138.00	138.00	Steel - SP		8.00	1
28	MCCLELLAND, UT	MIDVALLEY, UT	138.00	138.00	Wood - SP	6.00		1
29	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
30	MID VALLEY, UT	90TH SOUTH, UT	138.00	138.00	Wood - H	9.00		1
31	MID VALLEY #2, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	3.00		1
32	MID VALLEY #1, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	5.00		1
33	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	4.00	2.00	1
34	MIDDLETON, UT	ST. GEORGE, UT	138.00	138.00	Wood - H	1.00		1
35	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
36					TOTAL	16,965.00	651.00	288

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 ACSR 26/7								1
								2
397.5 ACSR 26/7								3
795 ACSR 26/7								4
1272 ACSR 45/7								5
1272 ACSR 45/7								6
1272 AAC /61								7
397.5 ACSR 26/7								8
1272 ACSR 45/7								9
397.5 ACSR 26/7								10
795 ACSR 45/7								11
795 ACSR 45/7								12
397.5 ACSR 26/7								13
1272 ACSR 45/7								14
1272 ACSR 45/7								15
795 ACSR 26/7								16
1272 ACSR 45/7								17
397.5 ACSR 26/7								18
250 CUHD /12								19
397.5 ACSR 26/7								20
397.5 ACSR 26/7								21
795 AAC /37								22
1272 AAC/91								23
1272 AAC /61								24
795 ACSR 26/7								25
								26
1272 ACSR 45/7								27
795 AAC 26/7								28
795 AAC 26/7								29
1272 ACSR 45/7								30
								31
								32
1272 ACSR /61								33
397.5 ACSR 26/7								34
397.5 ACSR 26/7								35
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	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 2019/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	NAUGHTON, WY	CANYON COMP, WY	138.00	138.00	Wood - H	35.00		1
2	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	44.00		1
3	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	33.00		1
4	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	10.00		1
5	ONEIDA, ID	OVID, UT	138.00	138.00	Wood - H	23.00		1
6	ONIEDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
7	OQUIRRH, UT	BARNEY, UT	138.00	138.00	Wood - H	5.00		1
8	OQUIRRH, UT	BINGHAM CANYON, UT	138.00	138.00	Wood - H	8.00		1
9	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Steel - SP	23.00		1
10	PAINTER, UT	RAILROAD, UT	138.00	138.00	Wood - H	7.00		1
11	PARRISH #105, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
12	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
13	PARRISH, UT	TAP TO N. SALT LAKE, UT	138.00	138.00	Steel - SP		8.00	1
14	PARRISH, UT	TERMINAL #1, UT	138.00	138.00	Steel - SP	16.00		1
15	PARRISH, UT	TERMINAL #2, UT	138.00	138.00	Steel - SP		14.00	1
16	RAILROAD, UT	CANYON COMP, WY	138.00	138.00	Wood - H	17.00		1
17	RED BUTTE, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	49.00		1
18	RIVERDALE, UT	EAST LAYTON, UT	138.00	138.00	Steel - SP		7.00	1
19	SHICK, UT	PARRISH, UT	138.00	138.00	Wood - H		10.00	1
20	SILVER CREEK, UT	JORDANELLE, UT	138.00	138.00	Wood - SP	10.00		1
21	SILVER CREEK, UT	RAILROAD, UT	138.00	138.00	Wood - SP	72.00		1
22	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
23	ST. GEORGE, UT	PURGATORY FLAT, UT	138.00	138.00	Wood - SP	10.00		2
24	SUNRISE, UT	OQUIRRH, UT	138.00	138.00	Wood - SP		2.00	1
25	SYRACUSE, UT	ANGEL #1, UT	138.00	138.00	Wood - SP		7.00	1
26	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	5.00		1
27	SYRACUSE, UT	PARRISH, UT	138.00	138.00	Steel Tower	15.00		1
28	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00	Wood - H	4.00		1
29	TAYLORSVILLE, UT	90TH SOUTH, UT	138.00	138.00	Wood - SP	6.00	2.00	1
30	TERMINAL, UT	KENNECOTT, UT	138.00	138.00	Steel - SP	9.00		1
31	TERMINAL, UT	MIDVALLEY #1, UT	138.00	138.00	Wood - H	7.00		1
32	TERMINAL, UT	MIDVALLEY #2, UT	138.00	138.00	Wood - H	7.00		1
33	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	53.00		1
34	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	24.00	6.00	1
35	TERMINAL, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	7.00		1
36					TOTAL	16,965.00	651.00	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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.
795 AAC 26/7								1
795 AAC 26/7								2
795 AAC 26/7								3
397.5 ACSR 26/7								4
336.4 ACSR 26/7								5
250 CUHD /12								6
795 AAC 26/7								7
1557.4 ACSR/TW								8
1272 ACSR 45/7								9
1272 ACSR 45/7								10
795 AAC 45/7								11
397.5 ACSR 26/7								12
795 AAC 26/7								13
795 AAC 45/7								14
795 AAC 26/7								15
795 ACSR 26/7								16
397.5 ACSR 26/7								17
795 AAC 26/7								18
250 CUHD /12								19
795 AAC 26/7								20
1272 ACSR 45/7								21
1272 ACSR 45/7								22
1272 ACSR 45/7								23
								24
250 CUHD /12								25
1272 ACSR 45/7								26
1272 ACSR 45/7								27
795 AAC /37								28
795 AAC /37								29
795 AAC 26/7								30
1272 ACSR 45/7								31
1272 AAC /61								32
795 AAC /37								33
397.5 ACSR 26/7								34
								35
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	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 2019/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	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
2	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
3	THREEMILE KNOLL, ID	MONSANTO #1, ID	138.00	138.00	Wood - H	2.00		1
4	THREEMILE KNOLL, ID	MONSANTO #2, ID	138.00	138.00	Steel - SP	2.00		1
5	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
6	TIMP #2, UT	DYNAMO, UT	138.00	138.00	Steel - SP		2.00	1
7	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
8	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	20.00		1
9	TIMP, UT	VINEYARD, UT	138.00	138.00	Wood - SP	2.00		1
10	TREASURETON, ID	GRACE, ID	138.00	138.00	Steel Tower	25.00		1
11	TREASURETON, ID	GRACE #2, ID	138.00	138.00	Steel Tower		25.00	1
12	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
13	TRI-CITY, UT	BANGERTER, UT	138.00	138.00	Wood - SP	6.00	12.00	1
14	TRI-CITY, UT	SUNRISE, ID	138.00	138.00	Wood - SP	22.00		1
15	TRI-CITY, UT	WESTFIELD, UT	138.00	138.00	Wood - H	15.00		1
16	WEST CEDAR, UT	THREE PEAKS, UT	138.00	138.00	Wood - SP	20.00		1
17	WEST VALLEY, UT	OQUIRRH, UT	138.00	138.00	Wood - H	9.00		1
18	WESTFIELD, UT	HALE, UT	138.00	138.00	Wood - H	13.00		1
19	WHEELON, UT	AMERICAN FALLS, ID	138.00	138.00	Wood - H	87.00		1
20	WHEELON #1, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
21	WHEELON #2, UT	TREASURETON, ID	138.00	138.00	Steel Tower		29.00	1
22	WHEELON #3, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
23	138kV costs and expenses							
24	Subtotal 138kV					2,222.00	205.00	149
25								
26	All 115kV Lines					1,655.00		
27								
28	All 69kV Lines					2,913.00		
29								
30	All 57kV Lines					107.00		
31								
32	All 46kV Lines					2,473.00		
33								
34								
35								
36					TOTAL	16,965.00	651.00	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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.
250 CUHD /12								1
1272 ACSR 45/7								2
1272 AAC /61								3
1272 ACSR 45/7								4
								5
								6
								7
								8
1272 ACSR 45/7								9
250 CUHD /12								10
250 CUHD /12								11
250 CUHD /12								12
								13
								14
1272 ACSR 45/7								15
795 AAC 26/7								16
								17
795 AAC 26/7								18
250 CUHD /12								19
250 CUHD /12								20
250 CUHD /12								21
250 CUHD /12								22
	34,308,615	410,150,732	444,459,347	342,800	2,209,841	152,371	2,705,012	23
	34,308,615	410,150,732	444,459,347	342,800	2,209,841	152,371	2,705,012	24
								25
	5,427,950	226,218,441	231,646,391	42,226	2,029,723	472,318	2,544,267	26
								27
	8,387,410	312,795,076	321,182,486	189,203	4,233,722	220,843	4,643,768	28
								29
	141,468	12,720,090	12,861,558	3,950	14,575	5,392	23,917	30
								31
	11,591,169	285,621,403	297,212,572	203,321	1,749,267	49,161	2,001,749	32
								33
								34
								35
	253,528,964	3,620,408,197	3,873,937,161	1,089,585	16,258,960	2,244,063	19,592,608	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.: 7 Column: i

1557 ACSR/TW 36/7

Schedule Page: 422.2 Line No.: 18 Column: a

Complete name is Gonder (NV Energy), Utah-Nevada State

Schedule Page: 422.2 Line No.: 21 Column: a

The Hurricane - Walla Walla 230kV line is jointly owned by PacifiCorp and Idaho Power Company 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: 422.2 Line No.: 30 Column: i

1158.4 ACSS/TW 25/7

Schedule Page: 422.4 Line No.: 1 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: 422.4 Line No.: 2 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.: 6 Column: a

The Goshen - Jefferson 161kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 77.0% and 23.0%, respectively. Plant cost and operation and maintenance costs reported for this line represents PacifiCorp’s share.

Schedule Page: 422.4 Line No.: 23 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.: 24 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.: 28 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.5 Line No.: 17 Column: a

The Central #2 - Saint 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.: 18 Column: a

The Central #3 - Saint 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.: 20 Column: b

Complete name is Burraston Ponds Metering, UT

Schedule Page: 422.6 Line No.: 2 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 26 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 31 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 32 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 8 Column: b

Complete name is Bingham Canyon (KCC), UT

Schedule Page: 422.7 Line No.: 24 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 35 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 5 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 6 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 7 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 8 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.: 14 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 17 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 19 Column: a

The Wheelon - American Falls 138kV line is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 96.4% and 3.6%, respectively. 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 2019/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	CORRAL, OR	OCHOCO #1, OR	9.00	Wood - H	8.00	1	1
2	MCNARY (BPA), OR	WALLULA, WA	29.00	Wood - H	8.00	1	1
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		38.00		16.00	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)	
1557	ACSR	Horiz. 20'	230	71,509	5,549,547	3,713,593		9,334,649	1
1158.4	ACSS	Horiz. 20'	230	5,160,691	11,344,287	13,513,307		30,018,285	2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
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									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				5,232,200	16,893,834	17,226,900		39,352,934	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 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CALIFORNIA				
2	BELMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	BIG SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	CASTELLA SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
5	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	DOG CREEK SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
7	DORRIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	FORT JONES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	GASQUET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	GREENHORN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	HAMBURG SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
12	HAPPY CAMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	HORNBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	INTERNATIONAL PAPER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
15	LAKE EARL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	LITTLE SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
17	LUCERNE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	MACDOEL SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
19	MCCLOUD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	MILLER REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MONTAGUE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MORRISON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
23	MOUNT SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	NEWELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NORTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NORTHCREST SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	NUTGLADE SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
28	PATRICKS CREEK SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
29	PEREZ SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	SCOTT BAR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SEIAD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SHASTINA SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
34	SHOTGUN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SMITH RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SNOW BRUSH SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
37	SOUTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
38	TULELAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	TUNNEL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	WALKER BRYAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
25	1					2
6	1					3
1	3					4
4	3					5
	1					6
7	3					7
6	1					8
9	1					9
12	1					10
1	1					11
7	3					12
4	3					13
9	3					14
12	1					15
2	3					16
4	1					17
30	2					18
6	1					19
4	3					20
6	1					21
14	1					22
16	4					23
12	1					24
6	6					25
20	4					26
1	3					27
1	1					28
1	3					29
9	3					30
2	3					31
2	3					32
6	3					33
1	1					34
6	3					35
1	3					36
2	3					37
20	1					38
6	6					39
9	3					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/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	EAST AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
35	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	EIGHT MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	GEORGETOWN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	GRACE CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	HAMER 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.
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
9	1					34
14	1					35
14	1					36
4	1					37
6	1					38
5	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 2019/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	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
3	HOLBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
9	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
10	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	REXBURG 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)	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)	
9	1					1
1	1					2
6	1					3
9	1					4
4	1					5
20	1					6
3	1					7
22	1					8
14	1					9
6	1					10
5	1					11
3	1					12
10	1					13
20	1					14
5	1					15
8	1					16
14	1					17
20	1					18
20	1					19
12	1					20
2	1					21
20	1					22
32	2					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 2019/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	

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
105	2					24
76	2					25
168	3					26
775	2					27
533	2					28
30	1					29
5186	32	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 2019/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 2019/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)	
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 2019/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	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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
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 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	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 SUB	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	

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 2019/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	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	

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 2019/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	12.47	
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	432.91	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	FRIEND SUB	TRANSMISSION-UNATTEN	230.00	115.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
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
120	7	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
1203	40	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
	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	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
2	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
3	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
4	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
5	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
6	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
7	MALIN SUB	TRANSMISSION-UNATTEN	500.00	230.00	69.00
8	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
9	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
10	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	
11	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
12	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
13	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
14	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
15	ROUNDUP SUB - BPA	TRANSMISSION-UNATTEN	230.00	69.00	
16	SANTIAM TIE - BPA	TRANSMISSION-UNATTEN	230.00	69.00	
17	SNOW GOOSE SUB	TRANSMISSION-UNATTEN	525.00	230.00	34.50
18	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
19	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
20	WHETSTONE SUB	TRANSMISSION-UNATTEN	230.00	115.00	12.47
21	TOTAL (Number of Substations-30)		7211.50	3163.50	478.24
22					
23	UTAH				
24	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
28	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	AMALGA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
32	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.20	12.47	
36	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	7.62	
37	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
38	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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)	
500	2					1
583	4	3				2
29	2					3
250	1					4
251	6	1				5
733	10					6
775	4	1				7
1300	6	1				8
50	1					9
114	1					10
150	1					11
500	2					12
30	3					13
50	1					14
67	2					15
75	1					16
650	1	1				17
500	3					18
100	2					19
250	1					20
8374	82	8				21
						22
						23
30	1					24
30	1					25
13	1					26
30	1					27
45	2					28
11	1					29
30	1					30
1	1					31
3	1					32
50	2					33
17	2					34
4	1					35
25	1					36
2	3					37
1	3					38
9	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
2	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
3	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
6	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	CANYONLANDS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	CARBIDE SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
11	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	CASTO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
16	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	CLEARFIELD SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	COALVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
27	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
28	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	CORINNE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
36	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
39	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	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 2019/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)	
14	1					1
29	2					2
6	1					3
60	3					4
11	3					5
9	1					6
12	1					7
1	1					8
20	1					9
3	1					10
6	1					11
30	1					12
25	1					13
22	1					14
9	1					15
30	1					16
50	2					17
3	1					18
4	1					19
	3					20
60	2					21
50	2					22
4	1					23
22	1					24
30	1					25
106	4					26
1	3					27
30	1					28
30	1					29
3	1					30
2	3					31
30	1					32
22	1					33
30	1					34
42	1					35
55	2					36
6	1					37
48	3					38
4	1					39
60	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	FERRON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
19	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	FORT DOUGLAS	DISTRIBUTION-UNATTEN	138.00	13.20	
23	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	FREEDOM SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
25	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
37	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
38	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
40	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

SUBSTATIONS (Continued)

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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)	
23	2					1
30	1					2
6	1					3
60	2					4
20	1					5
19	2					6
5	1					7
3	1					8
2	1					9
3	3					10
25	1					11
14	1					12
10	1					13
3	1					14
30	1					15
1	2					16
5	1					17
6	1					18
50	2					19
4	1					20
2	1					21
40	1					22
7	1					23
	1					24
22	1					25
12	1					26
14	1	2				27
30	1					28
30	1					29
2	1					30
50	2					31
23	1					32
20	2					33
60	2					34
3	1					35
3	3					36
60	2					37
25	1					38
50	2					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
5	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	IVINS SUB	DISTRIBUTION-UNATTEN	67.00	12.47	
7	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
8	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
16	KYUNE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
17	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
21	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	LISBON SUB	DISTRIBUTION-UNATTEN	70.60	12.47	
24	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
26	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
27	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
28	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	MANILA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	MANTUA SUB	DISTRIBUTION-UNATTEN	44.00	12.47	
33	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
40	MEDICAL 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.
32	2					1
22	1					2
12	2					3
1	1					4
2	1					5
30	1					6
13	2					7
30	1					8
30	1					9
4	1					10
3	1					11
5	1					12
7	1					13
60	2					14
7	1					15
	1					16
53	2					17
40	2					18
2	1					19
22	1					20
20	1					21
20	1					22
3	1					23
	1					24
1	1					25
20	1					26
1	1					27
4	1					28
12	1					29
30	1					30
22	1					31
2	1					32
14	1					33
20	1					34
3	1					35
9	1					36
6	1					37
20	1					38
42	2					39
57	4					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	MILFORD SUB	DISTRIBUTION-UNATTEN	138.00	46.00	
4	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
5	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
9	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	NIBLEY SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
17	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
22	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
23	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
32	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	PARIETTE SUB	DISTRIBUTION-UNATTEN	69.00	24.94	
34	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	PARKSIDE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
40	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
30	1					1
25	1					2
89	2					3
	1					4
2	1					5
19	2					6
3	1					7
7	2					8
6	1					9
5	1					10
6	1					11
6	1					12
7	1					13
20	1					14
5	1					15
14	1					16
25	1					17
2	1					18
25	1					19
22	1					20
25	1					21
45	2					22
14	1					23
24	2					24
6	1					25
22	1					26
3	1					27
20	1					28
14	1					29
48	2					30
4	1					31
5	1					32
14	1					33
42	2					34
60	2					35
50	2					36
16	2					37
6	1					38
55	2					39
2	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 2019/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	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	PONY EXPRESS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
7	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
11	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
12	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
15	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
16	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
26	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
28	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
33	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	SEGO CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	68.68	7.20	
36	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
38	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	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 2019/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.
14	1					1
22	1					2
25	1					3
14	1					4
60	2					5
60	2					6
2	1					7
4	1					8
60	2					9
4	1					10
15	1					11
2	1					12
1	3					13
14	1					14
12	1					15
45	2					16
45	2					17
5	1					18
22	2					19
11	1					20
40	2					21
20	1					22
5	1					23
4	1					24
30	1					25
24	3					26
	3					27
11	1					28
60	2					29
60	2					30
1	3					31
1	1					32
1	3					33
14	1					34
	1					35
20	1					36
60	2					37
20	1					38
2	1					39
40	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	46.00	
4	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	67.00	12.47	
13	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
14	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
19	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
21	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
23	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
24	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
26	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
27	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	VINEYARD SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
34	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
39	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
40	2					1
5	1					2
127	3					3
12	1					4
60	2					5
28	2					6
60	2					7
25	1					8
30	1					9
22	1					10
22	2					11
14	1					12
14	1					13
4	1					14
20	1					15
14	1					16
7	1					17
60	2					18
6	1					19
20	1					20
14	1					21
14	1					22
100	2					23
22	1					24
25	1					25
34	2					26
39	2					27
50	2					28
22	1					29
3	1					30
33	2					31
2	1					32
30	1					33
13	1					34
30	1					35
30	1					36
2	3					37
14	1					38
42	2					39
10	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 2019/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	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	WEST POINT SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
5	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
7	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	44.90	12.47	
11	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
12	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
13	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	TOTAL (Number of Substations-272)		20128.68	3524.38	105.44
17					
18	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
19	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
20	BDO SUB	T/D-UNATTENDED	138.00	12.47	
21	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
22	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
23	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
24	DECADE SUB	T/D-UNATTENDED	138.00	12.47	
25	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
26	EMMA PARK SUB	T/D-UNATTENDED	138.00	12.47	
27	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
28	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
29	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
30	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
31	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
32	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
33	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
34	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
35	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
36	PIONEER PLANT	T/D-UNATTENDED	138.00	12.47	
37	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
38	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
39	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
40	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	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 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
22	1					1
28	1					2
60	2					3
40	1					4
25	1					5
60	3					6
5	1					7
30	1					8
1	1					9
24	1					10
4	1					11
	1					12
6	1					13
20	1					14
2	1					15
5830	374	2				16
						17
1572	5					18
135	3					19
30	1					20
205	4					21
40	2					22
289	7					23
60	2					24
60	2					25
8	1					26
72	3					27
114	2					28
97	2					29
164	2					30
22	1					31
340	3					32
65	2					33
835	4	1				34
97	2					35
30	1					36
180	3					37
34	4					38
100	2					39
50	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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SYRACUSE SUB	T/D-UNATTENDED	345.00	138.00	46.00
2	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
3	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
4	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
5	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
6	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
7	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
8	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
9	TOTAL (Number of Substations-31)		5014.00	1006.46	768.70
10					
11	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
12	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
13	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
14	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
15	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
16	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
17	BLACK ROCK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
18	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
19	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
20	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
21	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40
22	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
23	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
24	CROYDON SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
25	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
26	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
27	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
28	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
29	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
30	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
31	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
32	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
33	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	24.90
34	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
35	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
36	MATHINGTON SUB	TRANSMISSION-UNATTEN	138.00	46.00	13.20
37	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
38	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
39	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
40	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	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 2019/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)	
1300	6					1
358	4					2
1108	6	2				3
130	2					4
249	3					5
30	1					6
30	1					7
20	1					8
7824	84	3				9
						10
783	13					11
318	2					12
67	1					13
133	2					14
100	1					15
1813	5					16
75	1					17
100	2					18
25	4					19
169	2					20
448	1					21
71	2					22
40	2					23
81	2					24
50	1					25
312	3					26
33	1					27
67	2					28
225	3					29
77	2					30
35	1					31
80	2					32
270	4					33
67	1					34
75	1					35
160	5	1				36
45	1					37
137	3					38
900	2					39
67	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 2019/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	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
2	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
3	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
4	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
5	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
6	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
7	PURGATORY FLAT SUBSTATION	TRANSMISSION-UNATTEN	138.00	69.00	12.47
8	RED BUTTE SUB	TRANSMISSION-UNATTEN	345.00	138.00	
9	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
10	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
11	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	13.80
12	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
13	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
14	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
15	TOTAL (Number of Substations-44)		8579.00	3446.77	704.62
16					
17	WASHINGTON				
18	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
21	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
24	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
25	GROMORE SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
26	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	NACHES SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
28	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	116.00	13.20	
35	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
38	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
40	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	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)	
12	1					1
67	1					2
67	1					3
138	2					4
133	2					5
258	3					6
300	2					7
414	2					8
1124	6					9
63	2					10
1100	2					11
100	3	1				12
450	1					13
262	3					14
11311	104	2				15
						16
						17
25	1					18
45	2					19
118	6					20
25	1					21
23	2					22
25	4					23
42	2					24
25	1					25
50	2					26
25	1					27
42	2					28
45	2					29
50	2					30
28	3					31
9	1					32
40	2					33
44	3					34
76	5					35
45	2					36
25	1					37
45	2					38
29	2					39
50	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 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	TOTAL (Number of Substations-30)		3038.00	383.42	107.66
9					
10	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
11	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
12	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
13	TOTAL (Number of Substations-3)		368.00	139.94	12.47
14					
15	DRY GULCH SUB - AVISTA	TRANSMISSION-UNATTEN	115.00	69.00	
16	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
17	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
18	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
19	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
20	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
21	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
22	TOTAL (Number of Substations-7)		1380.00	621.00	20.40
23					
24	WYOMING				
25	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
26	ARROWHEAD SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
27	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
28	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
29	BAR NUNN	DISTRIBUTION-UNATTEN	115.00	12.47	
30	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
31	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
33	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
34	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
35	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
37	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
38	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	CHAPMAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					1
25	1					2
9	1					3
45	2					4
25	2					5
22	2					6
45	2					7
1108	62					8
						9
14	1					10
45	2					11
595	5					12
654	8					13
						14
20	1					15
125	1					16
39	9					17
325	3					18
300	2					19
120	2					20
250	1					21
1179	19					22
						23
						24
25	1					25
150	2					26
12	1					27
2	1					28
30	1					29
25	1					30
7	1					31
14	1					32
150	2					33
73	4					34
25	1					35
2	3					36
2	6					37
12	1					38
4	1					39
1	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
2	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
3	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
4	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
6	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
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	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
40	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	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 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1	1					1
4	1					2
45	2					3
50	2					4
5	3					5
9	1					6
12	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
55	2					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
30	1					39
5	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
2	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
3	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
4	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
5	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
6	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
7	RED BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
8	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
10	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
11	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
13	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
14	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
15	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
16	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
17	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
18	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
19	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
20	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
21	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
22	WAPA THERMOPOLIS	DISTRIBUTION-UNATTEN	115.00	34.50	
23	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
24	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
25	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
26	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
27	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
28	TOTAL (Number of Substations-83)		7761.44	1367.35	38.17
29					
30	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
31	ELK HORN SUB	T/D-UNATTENDED	115.00	12.47	
32	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
33	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
34	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
35	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
36	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
37	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
38	TOTAL (Number of Substations-8)		1449.00	208.64	55.30
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
16	9	2				2
3	1					3
2	3					4
12	1					5
200	2					6
30	1					7
45	2					8
6	1					9
2	3					10
1	1					11
14	3	1				12
2	6					13
150	2					14
28	1					15
2	3					16
5	1					17
12	1					18
5	1					19
9	1					20
25	2					21
25	1					22
2	6					23
3	1					24
25	1					25
5	1					26
20	1	1				27
1880	145	4				28
						29
20	1	1				30
25	1					31
50	2					32
45	2	1				33
8	6					34
25	1					35
76	4					36
25	1					37
274	18	2				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 2019/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 - 30				
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
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
5186						31
						32
						33
200						34
						35
						36
4653						37
1203						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 2019/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 - 83				
13	T/D - 8				
14	Transmission - 20				
15					
16	ALL STATES				
17	Distribution - 668				
18	T/D - 61				
19	Transmission - 127				
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 2019/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
5830						2
7824						3
11311						4
						5
						6
1108						7
654						8
1179						9
						10
						11
1880						12
274						13
3817						14
						15
						16
14530						17
10397						18
30792						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
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						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.: 3 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.: 7 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.: 8 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.: 15 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.: 16 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 responsibility for performance.

Schedule Page: 426.9 Line No.: 17 Column: g

Represents one 3-phase bank

Schedule Page: 426.19 Line No.: 15 Column: a

The Dry Gulch 115kV Substation property is jointly 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.: 19 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 2019/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	162,711,322
3	Coal purchases	Trapper Mining Inc.	151,501	15,086,319
4	Administrative services under the IASA	BHE	426.4,426.5,923	4,963,789
5	Administrative services under the IASA	MEC	426.4,426.5,923	4,401,310
6	Administrative services under the IASA	MHC Inc.	426.5	494,378
7	Administrative services under the IASA	Kern River Gas Transmission Company	923	93
8	Gas transportation services	Kern River Gas Transmission Company	547	3,080,471
9	Rail services and right-of-way fees	BNSF Railway Company	151,501,507,567,589	35,201,754
10	Employee relocation services	HomeServices of America, Inc.		1,312,195
11	Travel services	Delta Air Lines, Inc.		1,193,177
12	Financial transactions related to energy hedging	J. Aron & Company LLC	419,501,507	14,666,938
13	Banking services	Wells Fargo & Company		1,107,114
14	Banking services and rating agency fees	U.S. Bank National Association		355,291
15	Rating agency fees	Moody's Investors Service, Inc.		500,454
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information technology and administrative			
22	support services	Bridger Coal Company	501,557,931,426.5	1,341,044
23	Administrative services under the IASA	MEC		428,101
24	Financial transactions related to energy hedging	Wells Fargo & Company	501,547	344,870
25				
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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.: 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.: 9 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

$ 35,158,552	Rail services
43,202	Right-of-way fees(1)
$ 35,201,754	

(1) 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.: 10 Column: c

Accounts charged for HomeServices of America, Inc.: 500, 506, 535, 539, 548, 549, 553, 557, 560, 568, 580, 581, 590, 593, 903, 809 and 921.

Schedule Page: 429 Line No.: 11 Column: c

Accounts charged for Delta Air Lines, Inc.: 107, 416, 426.4, 502, 506, 511, 513, 535, 539, 544, 548, 549, 553, 556, 557, 560, 561.2, 561.5, 568, 569.3, 580, 581, 585, 588, 590, 592, 593, 595, 598, 901, 903, 907, 908, 909, 920, 921, 922 and 928.

Schedule Page: 429 Line No.: 12 Column: b

J. Aron & Company LLC is a subsidary of The Goldman Sachs Group, Inc. which is an affiliated company.

Schedule Page: 429 Line No.: 13 Column: c

Accounts charged for Wells Fargo & Company: 228.3, 419, 426.5, 427, 431, 903, 921 and 928.

Schedule Page: 429 Line No.: 14 Column: b

U.S. Bank National Association is a subsidary of U.S. Bancorp which is an affiliated company.

FOOTNOTE DATA

Schedule Page: 429 Line No.: 14 Column: c

Accounts charged for U.S. Bank National Association: 419, 427, 431, 537, 557, 903, 920, 928 and 930.2.

Schedule Page: 429 Line No.: 15 Column: c

Accounts charged for Moody's Investors Service, Inc.: 181, 186, 427, 428 and 930.2.

Schedule Page: 429 Line No.: 23 Column: c

Accounts charged for MEC: 107, 426.5, 557, 580, 920, 921, 922, 923 and 931.

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