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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER COMPANY TO APPROVE ITS CAPACITY DEFICIENCY PERIOD FOR AVOIDED COST CALCULATIONS	)	**CASE NO. PAC-E-17-09** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Daphne Huang, Deputy Attorney General, and in response to the Notice of Application and Notice of Modified Procedure issued in Order No. 33869, submits the following comments.

BACKGROUND

On August 18, 2017, PacifiCorp dba Rocky Mountain Power Company filed an Application asking the Commission to approve its updated capacity deficiency period for use in its avoided cost calculations under the Public Utility Regulatory Policies Act (PURPA), using the Surrogate Avoided Resource (SAR) methodology.

Under PURPA, electric utilities must purchase electric energy from qualifying facilities (QFs) at rates approved by the applicable state regulatory agency – in Idaho, this Commission. 16 U.S.C. § 824a-3; *Idaho Power Co. v. Idaho PUC*, 155 Idaho 780, 789, 316 P.3d 1278, 1287

(2013). The purchase or "avoided cost" rate shall not exceed the "'incremental cost' to the purchasing utility of power which, but for the purchase of power from the QF, such utility would either generate itself or purchase from another source." Order No. 32697 at 7, *citing Rosebud Enterprises v. Idaho PUC*, 128 Idaho 624, 917 P.2d 781 (1996); 18 C.F.R. § 292.101(b)(6) (defining "avoided cost").

The Commission has established two methods of calculating avoided cost, depending on the size of the QF project: (1) the surrogate avoided resource (SAR) methodology, and (2) the integrated resource plan (IRP) methodology. *See* Order No. 32697 at 7-8. At issue in this case is the SAR methodology, which the Commission uses to establish "published" avoided cost rates. *Id.* Published rates are available for wind and solar QFs with a design capacity of up to 100 kilowatts (kW), and for QFs of all other resource types with a design capacity of up to 10 average megawatts (aMW). *Id.*

In calculating avoided cost, the Commission found it "reasonable, appropriate and in the public interest to compensate QFs separately based on a calculation of not only the energy they produce, but the capacity that they can provide to the purchasing utility." *Id.* at 16. As to the capacity calculation, the Commission found it appropriate "to identify each utility's capacity deficiency based on load and resource balances found in each utility's IRP." *Id.* The Commission elaborated:

> In calculating a QF's ability to contribute to a utility's need for capacity, we find it reasonable for the utilities to only begin payments for capacity at such time that the utility becomes capacity deficient. If a utility is capacity surplus, then capacity is not being avoided by the purchase of QF power. By including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power.

Id. at 21.

The Commission directed that "when a utility submits its [IRP] to the Commission, a case shall be initiated to determine the capacity deficiency to be utilized in the SAR Methodology." *Id.* at 23. The Commission also stated "utilities must update fuel price forecasts and load forecasts annually – between IRP filings. . . . We find it reasonable that all other variables and assumptions utilized within the IRP Methodology remain fixed between IRP filings (every two years)." *Id.* at 22.

Rocky Mountain's Application states it filed its 2017 IRP (Case No. PAC-E-17-03) with the Commission on April 4, 2017. The Company's 2017 IRP includes the results of its capacity balance, which is "calculated for summer peak loads only." Application at 3. Also, the 2017 IRP "shows that the Company first becomes capacity deficient in 2028." *Id.*

Rocky Mountain identifies two factors affecting the capacity deficit period reflected in its 2017 IRP: (1) power purchase agreements with QFs signed since preparation of the 2017 IRP; and (2) termination of a power purchase agreement originally included in the 2017 IRP. *Id.* at 4. After accounting for these factors, Rocky Mountain states that its "capacity deficit still first occurs in the summer of 2028." *Id.*

Rocky Mountain's Application includes Table 2, which shows "updated system capacity loads and resources." *Id.* Table 2 reflects the inclusion of 460 megawatts (MW) of nameplate capacity from nine additional QF contracts, as well as the removal of one QF contract, thus eliminating five MW of nameplate capacity. *Id.* at 4-5. The Company asks the Commission to approve a capacity deficiency period, for calculating SAR based avoided cost rates, of summer 2028.

STAFF ANALYSIS

Authorization of First Capacity Deficiency Date

Staff recommends that the Commission authorize July 2028 as the first capacity deficiency date for valuing contracts that use the SAR methodology. According to the Company's filing, a first capacity deficiency of 270 megawatts will occur in July 2028. This change will push back the deficit date three years from the currently authorized date of July 2025.

Staff compared the 2017 Summer Load and Existing Resource Balance to the 2015 Summer Load and Existing Resource Balance which was used to determine the currently authorized July 2025 first capacity deficiency date. By comparing average annual loads and average annual resource capacity between 2025 and 2028, Staff identified a 1393 MW annual average reduction in demand and a 473 MW decrease in supply resources for a net reduction in demand that delays the need for new capacity for an additional three years.

There were two factors decreasing demand: an 829 MW average annual increase in Class 2 demand side management resources (DSM) and a 379 MW reduction in the load forecast. The increase in Class 2 DSM is the result of including all cost-effective Class 2 DSM from the Company's DSM potential study that was included in its preferred portfolio to resolve deficits in the load resource balance. Although this is a change in PacifiCorp's methodology from its 2015 IRP, it is effectively the same method Idaho Power uses to establish the first deficit capacity year by netting all cost-effective DSM from its load forecast. Staff believes that this change is reasonable because the Company is expected to pursue all cost- effective DSM selected in its preferred portfolio prior to the first deficit date occurring. This will effectively push out the deficit date to the time period when new PURPA projects not yet in the queue will contribute to capacity deficiency.

PacifiCorp also decreased its load forecast in the 2017 IRP, primarily due to reduction in industrial and residential class customer loads. According to the Company, industrial class loads are projected to be smaller due to lower industrial commodity prices. The Company also assumed increased penetration of distributed generation and changes in building codes which caused average use per customer decreases for residential customers. Staff believes these assumptions are reasonable.

As to the amount of available resources, PacifiCorp has seen a 473 MW decrease in its 2017 load and resource balance as compared to the Company's 2015 load and resource balance. This usually results in an earlier deficit date but is not large enough to offset the reduction in demand discussed above. The Company has assumed that thermal generation capacity will be reduced by 755 MW from the early shutdown of the Cholla 4, Craig 1, and Naughton 3 coal plants that was not assumed in the 2015 IRP. However, capacity from qualifying facilities has increased by 380 MW moderating the effects of the thermal generation reductions.

Staff believes the changes in the 2017 IRP causing the three-year shift in the first deficit date are reasonable. Staff updated the SAR model based on the new deficiency date and calculated new avoided cost rates, included as an attachment to these comments.

Timing of First Capacity Deficiency Date Filing

While Order No. 32697 directs all three electric utilities to file their first capacity deficiency case after submitting their IRP report to the Commission, Staff respectfully suggests that cases seeking first capacity deficiency date authorizations for all three utilities be filed after Commission IRP acknowledgement.

Staff has found that the scope of review to determine the reasonableness of the proposed deficiency date must sometimes consider a large subset of factors that are typically reviewed for IRP acknowledgement. However, Staff's review and Commission acknowledgment of the IRP can occur several months after the first capacity deficiency date cases are settled. Staff believes it would be more efficient and appropriate to delay capacity deficiency filings until after Commission IRP acknowledgment. This would eliminate duplication of effort between the two types of cases and ensure that all factors that could affect the first capacity deficiency date are covered through the comprehensive nature of the IRP acknowledgement review.

STAFF RECOMMENDATION

Staff has updated the SAR model and the avoided cost rates and recommends that the Commission approve the new rates to reflect the first deficiency date of July 2028. Staff also recommends that cases seeking first capacity deficiency date authorizations for all three utilities should be filed after Commission IRP acknowledgement starting with the 2019 IRPs.

Respectfully submitted this 28th day of September 2017.

Daphne Huang
Deputy Attorney General

Technical Staff: Yao Yin

i:umisc:comments/pace17.9djhyybe comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 28TH DAY OF SEPTEMBER 2017, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-17-09, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Jo Nelson
SECRETARY

PACIFICORP
AVOIDED COST RATES FOR WIND PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects 100 kW or smaller.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2017	2018	2019	2020	2021	2022		
1	28.61	31.48	34.42	35.95	36.78	36.36	2017	28.61
2	29.99	32.89	35.15	36.35	36.57	36.71	2018	31.48
3	31.35	33.83	35.65	36.35	36.74	37.35	2019	34.42
4	32.37	34.49	35.81	36.52	37.19	38.39	2020	35.95
5	33.12	34.81	36.03	36.90	38.02	39.45	2021	36.78
6	33.57	35.12	36.40	37.60	38.91	40.33	2022	36.36
7	33.96	35.53	37.04	38.38	39.69	41.47	2023	37.10
8	34.41	36.14	37.75	39.09	40.71	42.45	2024	38.76
9	35.03	36.82	38.40	40.01	41.61	43.27	2025	42.05
10	35.69	37.44	39.24	40.83	42.38	43.98	2026	44.58
11	36.30	38.23	40.00	41.54	43.04	44.61	2027	45.89
12	37.05	38.95	40.67	42.17	43.65	45.18	2028	50.51
13	37.74	39.59	41.26	42.75	44.20	45.71	2029	51.96
14	38.36	40.17	41.81	43.27	44.71	46.23	2030	52.69
15	38.92	40.70	42.32	43.76	45.21	46.72	2031	53.42
16	39.43	41.18	42.79	44.24	45.68	47.20	2032	54.56
17	39.91	41.64	43.24	44.69	46.14	47.65	2033	55.41
18	40.36	42.08	43.68	45.13	46.57	48.08	2034	56.64
19	40.78	42.50	44.10	45.55	46.99	48.51	2035	58.08
20	41.20	42.91	44.50	45.95	47.40	48.91	2036	59.54
							2037	61.19
							2038	62.35
							2039	63.89
							2040	65.78
							2041	66.92
							2042	68.93

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

PACIFICORP
AVOIDED COST RATES FOR SOLAR PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects 100 kW or smaller.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2017	2018	2019	2020	2021	2022		
1	28.61	31.48	34.42	35.95	36.78	36.36	2017	28.61
2	29.99	32.89	35.15	36.35	36.57	36.71	2018	31.48
3	31.35	33.83	35.65	36.35	36.74	37.35	2019	34.42
4	32.37	34.49	35.81	36.52	37.19	38.39	2020	35.95
5	33.12	34.81	36.03	36.90	38.02	39.45	2021	36.78
6	33.57	35.12	36.40	37.60	38.91	40.33	2022	36.36
7	33.96	35.53	37.04	38.38	39.69	45.02	2023	37.10
8	34.41	36.14	37.75	39.09	43.69	48.69	2024	38.76
9	35.03	36.82	38.40	42.54	46.93	51.63	2025	42.05
10	35.69	37.44	41.42	45.41	49.58	54.04	2026	44.58
11	36.30	40.13	43.99	47.81	51.80	56.09	2027	45.89
12	38.72	42.45	46.17	49.85	53.72	57.85	2028	82.17
13	40.83	44.45	48.05	51.64	55.38	59.40	2029	84.09
14	42.67	46.19	49.70	53.20	56.86	60.80	2030	85.29
15	44.29	47.74	51.17	54.60	58.20	62.06	2031	86.50
16	45.74	49.11	52.49	55.88	59.42	63.23	2032	88.13
17	47.03	50.36	53.70	57.04	60.54	64.29	2033	89.47
18	48.22	51.51	54.81	58.12	61.57	65.27	2034	91.19
19	49.30	52.56	55.84	59.11	62.53	66.20	2035	93.14
20	50.31	53.54	56.78	60.02	63.42	67.05	2036	95.12
							2037	97.29
							2038	98.99
							2039	101.06
							2040	103.49
							2041	105.19
							2042	107.77

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

PACIFICORP
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2017	2018	2019	2020	2021	2022	CONTRACT YEAR	NON-LEVELIZED RATES
1	28.61	31.48	34.42	35.95	36.78	36.36	2017	28.61
2	29.99	32.89	35.15	36.35	36.57	36.71	2018	31.48
3	31.35	33.83	35.65	36.35	36.74	37.35	2019	34.42
4	32.37	34.49	35.81	36.52	37.19	38.39	2020	35.95
5	33.12	34.81	36.03	36.90	38.02	39.45	2021	36.78
6	33.57	35.12	36.40	37.60	38.91	40.33	2022	36.36
7	33.96	35.53	37.04	38.38	39.69	44.67	2023	37.10
8	34.41	36.14	37.75	39.09	43.40	48.09	2024	38.76
9	35.03	36.82	38.40	42.30	46.41	50.82	2025	42.05
10	35.69	37.44	41.21	44.97	48.88	53.06	2026	44.58
11	36.30	39.95	43.60	47.20	50.95	54.97	2027	45.89
12	38.56	42.11	45.63	49.11	52.74	56.62	2028	79.10
13	40.53	43.98	47.39	50.77	54.30	58.07	2029	80.97
14	42.25	45.60	48.94	52.24	55.68	59.38	2030	82.12
15	43.77	47.05	50.31	53.55	56.94	60.57	2031	83.29
16	45.12	48.34	51.55	54.75	58.09	61.67	2032	84.87
17	46.34	49.52	52.68	55.84	59.15	62.67	2033	86.16
18	47.45	50.59	53.73	56.86	60.12	63.60	2034	87.84
19	48.48	51.59	54.70	57.79	61.02	64.48	2035	89.74
20	49.42	52.51	55.59	58.66	61.87	65.29	2036	91.67
							2037	93.78
							2038	95.43
							2039	97.45
							2040	99.83
							2041	101.47
							2042	104.00

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

PACIFICORP
AVOIDED COST RATES FOR SEASONAL HYDRO PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2017	2018	2019	2020	2021	2022	CONTRACT YEAR	NON-LEVELIZED RATES
1	28.61	31.48	34.42	35.95	36.78	36.36	2017	28.61
2	29.99	32.89	35.15	36.35	36.57	36.71	2018	31.48
3	31.35	33.83	35.65	36.35	36.74	37.35	2019	34.42
4	32.37	34.49	35.81	36.52	37.19	38.39	2020	35.95
5	33.12	34.81	36.03	36.90	38.02	39.45	2021	36.78
6	33.57	35.12	36.40	37.60	38.91	40.33	2022	36.36
7	33.96	35.53	37.04	38.38	39.69	47.09	2023	37.10
8	34.41	36.14	37.75	39.09	45.43	52.33	2024	38.76
9	35.03	36.82	38.40	44.02	50.03	56.50	2025	42.05
10	35.69	37.44	42.70	48.09	53.78	59.91	2026	44.58
11	36.30	41.25	46.32	51.47	56.91	62.78	2027	45.89
12	39.69	44.50	49.38	54.33	59.59	65.24	2028	100.64
13	42.64	47.28	52.00	56.82	61.90	67.38	2029	102.84
14	45.19	49.70	54.31	58.99	63.95	69.30	2030	104.31
15	47.42	51.84	56.34	60.92	65.78	71.01	2031	105.79
16	49.41	53.74	58.15	62.66	67.44	72.58	2032	107.70
17	51.19	55.45	59.80	64.24	68.95	73.99	2033	109.33
18	52.80	57.01	61.30	65.69	70.32	75.30	2034	111.35
19	54.27	58.43	62.68	67.01	71.59	76.51	2035	113.60
20	55.62	59.74	63.94	68.23	72.77	77.63	2036	115.87
							2037	118.35
							2038	120.35
							2039	122.74
							2040	125.49
							2041	127.51
							2042	130.42

Note: A "seasonal hydro project" is defined as a generation facility which produces at least 55% of its annual generation during the months of June, July, and August. Order 32802.

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

PACIFICORP
AVOIDED COST RATES FOR OTHER PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2017	2018	2019	2020	2021	2022	CONTRACT YEAR	NON-LEVELIZED RATES
1	28.61	31.48	34.42	35.95	36.78	36.36	2017	28.61
2	29.99	32.89	35.15	36.35	36.57	36.71	2018	31.48
3	31.35	33.83	35.65	36.35	36.74	37.35	2019	34.42
4	32.37	34.49	35.81	36.52	37.19	38.39	2020	35.95
5	33.12	34.81	36.03	36.90	38.02	39.45	2021	36.78
6	33.57	35.12	36.40	37.60	38.91	40.33	2022	36.36
7	33.96	35.53	37.04	38.38	39.69	43.74	2023	37.10
8	34.41	36.14	37.75	39.09	42.62	46.44	2024	38.76
9	35.03	36.82	38.40	41.63	45.01	48.62	2025	42.05
10	35.69	37.44	40.63	43.76	46.98	50.41	2026	44.58
11	36.30	39.45	42.55	45.55	48.64	51.95	2027	45.89
12	38.12	41.19	44.19	47.08	50.09	53.28	2028	70.76
13	39.72	42.70	45.60	48.43	51.35	54.47	2029	72.51
14	41.12	44.02	46.86	49.62	52.48	55.54	2030	73.53
15	42.35	45.20	47.98	50.69	53.52	56.53	2031	74.57
16	43.46	46.25	48.99	51.68	54.47	57.45	2032	76.02
17	44.47	47.22	49.93	52.59	55.35	58.29	2033	77.19
18	45.38	48.11	50.80	53.44	56.16	59.07	2034	78.74
19	46.23	48.94	51.60	54.22	56.93	59.82	2035	80.50
20	47.02	49.71	52.35	54.95	57.65	60.51	2036	82.29
							2037	84.27
							2038	85.78
							2039	87.66
							2040	89.89
							2041	91.39
							2042	93.77

Note: "Other projects" refers to projects other than wind, solar, non-seasonal hydro, and seasonal hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm