ROCKY MOUNTAIN
POWER
A DIVISION OF PACIFICORP

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September 3, 2025

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

RE: Docket No. 25-035-T03
Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities
Rocky Mountain Power Reply Comments

I. Introduction

On April 23, 2025, Rocky Mountain Power (the "Company") filed its annual update to avoided cost pricing in Schedule 37. The Commission established a July 18, 2025, deadline for initial comments, and a September 3, 2025 deadline for reply comments. On July 18, 2025, the Division of Public Utilities ("Division"), Salt Lake City Corporation ("City"), and Western Resource Advocates ("WRA") filed initial comments. The Division's comments recommend that the Commission approve the Company's filing, with certain corrections that were identified in the June 18, 2025, Technical Conference in this docket.[1]

The City requests several changes to the avoided cost assumptions and inputs, including use of the Utah, Idaho, Wyoming, and California (UIWC) full jurisdictional portfolio from the 2025 IRP[2] rather than the Utah 2025 IRP preferred portfolio,[3] or the final 2025 IRP preferred portfolio[4] (which included updates after the data lockdown date specified by the Commission in Docket No. 23-035-10).[5] In addition, the City proposes higher capital costs for wind and solar, as well as the exclusion of the Natrium advanced nuclear demonstration project from the portfolio used to determine avoided cost pricing.

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[1] *E.g.,* RMP's Technical Conference Presentation, Docket No. 25-035-T03, slides 5-9 (June 18, 2025) ("Following the filing of the 2025 IRP, PacifiCorp identified an error in the escalation rates applied to solar, wind, and storage resources: escalation rates for proxy resources started in 2025 but should have been applied from the earliest commercial operations year") (available here: https://pscdocs.utah.gov/electric/25docs/25035T03/340262RMPPrsntnJun182025VrtlTchnclCnfrnc6-18-2025.pdf).
[2] *In re PacifiCorp's 2025 Utah IRP,* Table 9.7 (available here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_IRP_Vol_1_Utah.pdf).
[3] *Id.*, Table 12.10.
[4] *Id.,* Table 9.10.
[5] Docket No. 23-035-10, Commission Order, at 5-6 (Sept. 24, 2024).

WRA requests that avoided cost prices not be updated until stakeholders have had the opportunity to comment on the 2025 IRP, and that the timing of future avoided cost updates similarly be delayed to allow stakeholder review of a filed IRP. If avoided cost pricing is to be updated at this time, WRA recommends that it be based on current modeling assumptions and the UIWC full jurisdictional portfolio. WRA also recommends that renewable qualifying facilities (QFs) be allowed to retain their renewable energy credits (RECs) when deferring IRP proxy resources.

In accordance with the Commission's June 9, 2025 Scheduling Order, Rocky Mountain Power replies to each of these recommendations below. The Company's comments are grouped into three categories, addressing resource cost assumptions, the resource portfolio used to determine avoided cost pricing, and other topics raised by WRA.

II. <u>Resource Cost Recommendations</u>

First, as referenced by DPU and identified in the Company's technical conference presentation, the escalation rates for wind and solar resource build costs were applied incorrectly in the 2025 IRP. Correcting the escalation rates results in a slight increase in solar QF pricing and a slight reduction in wind QF pricing.

Second, the City raises concerns regarding changes to production tax credit eligibility that could impact wind and solar resources reaching commercial operation after the end of 2027 or after the end of 2029. This could potentially impact the deferrable resource for solar, which has an assumed online date of January first (or year-end 2031). Despite that online date occurring after the end of PTC eligibility for solar resources, PacifiCorp does not support the removal of the PTC in this instance, as the resource may not have been cost-effective in the absence of the value of the PTC that was considered in the determination of the preferred portfolio. Had the model known that PTCs were no longer available after 2030 (or yearend 2029), it would have had the opportunity to accelerate resource selections to maintain PTC eligibility and/or reduce selections in years where PTCs were no longer available. PacifiCorp has not reoptimized the preferred portfolio in light of these changes, and unlike the other changes addressed in this resource cost section, would need to prepare additional modeling results to modify the timing or composition of resources in the preferred portfolio. PacifiCorp can perform that modeling if required, but would reiterate that PacifiCorp does not support the calculation of avoided costs based on a proxy solar resource that is not eligible for PTCs.

Third, the City raises concerns about the change in the Company's capital cost assumptions in current avoided costs (filed in May 2024) and as in this proceeding (filed in April of 2025). The City then identifies a number of tax and tariff related events in the intervening period that could contribute to higher costs for renewable resources. The Company would note that the resource cost assumptions in its May 2024 avoided cost filing were consistent with assumptions in its 2023 IRP Update, and unchanged from estimates used in its 2023 IRP, which were developed based on information available during the summer of 2022. Similarly, resource cost assumptions in this proceeding reflect assumptions in the 2025 IRP, which were developed based on information available during the summer of 2024. The inclusion of assumptions from the most recently filed IRP or IRP

Update is identified as a "Routine Update" in the procedures for Schedule 38 avoided cost input changes adopted by the Commission in Docket No. 14-035-140.[6] Per the approved procedures, Routine Updates are incorporated into avoided cost pricing without prior notification or agreement from parties. Had the Company sought to modify the resource cost assumptions used in the 2025 IRP, it would have been considered a Non-Routine Update under the approved procedures. The Company would have been required to identify the change in its Schedule 38 quarterly compliance filing and would not have incorporated the change in the calculation avoided costs unless the change went unchallenged for three weeks after the filing or until a change that was challenged was resolved by the Commission. As a result, because the potential resource cost drivers referenced by the City were primarily based on events that occurred after data inputs were locked down for the 2025 IRP, the changes would have been considered a Non-Routine Update. For this reason, the Commission should decline to address the City's argument.

If the Commission decides to address this issue on the merits, PacifiCorp provides the following analysis. To address its concerns about renewable resource costs, the City recommends that proxy resource costs be increased to $1,481 per kilowatt for wind and $1,379 per kilowatt for solar, through the first five years of 2025 IRP study horizon (2025-2029). The Company estimates that, relative to capital costs with corrected escalation, the City's proposal is a 6% increase for wind, and a 10% increase for solar, as shown in Table 1. Because avoided costs also reflect fixed operations and maintenance costs, PTC benefits, and differences in generation profiles and locations, the effective impact varies.

Table 1: Comparison of Capital Costs

	Originally Filed	*Corrected Escalation*	*SLC Proposal (2025-2029)*	*SLC vs Corrected*	
	Estimated Capital Cost			Capital Cost Change	First year proxy avoided cost pricing change
Resource	$/kW			%	$/MWh
Wind (2028)	$1,455	$1,395	$1,481	6%	+$1.45
Solar (2029)		$1,258	$1,379	10%	
Solar (2030)		$1,224	$1,342 (a)	10%	
Solar (2031)		$1,188	$1,303 (a)	10%	
Solar (2032)	$1,029	$1,150	$1,261 (a)	10%	+$2.89

(a) Estimated based on corrected solar escalation from 2029 to 2032

A summary of the impacts of the Company's proposed modifications and the City's proposal is shown in Tables 2 and 3 for solar and wind, respectively. Also shown in those tables is the levelized cost for Utah solar and Wyoming wind, using either the City's resource cost proposal or the corrected inputs in the 2025 IRP. The current solar avoided cost results reflect a Willamette Valley,

[6] Docket No. 14-035-140, Order, at 5-7 (Jun. 9, 2015).

Oregon solar resource, which may not be well-aligned with a solar QF in Utah due to transmission limitations and differences in need between the east and west sides of the system. Similarly, while the wind avoided cost results reflect a Wyoming wind resource, they also reflect transmission limitations and differences in need between Wyoming and Utah. Even using the City's proposed capital cost, Utah solar resource costs would be lower than the avoided costs calculated using the Schedule 37 Proxy/Partial Displacement Differential Revenue Requirement (PDDRR) methodology, which indicates that, if there was a need for solar resources in Utah, it could be met at a lower cost than is reflected in the Schedule 37 results. This Utah solar resource was also selected in 2031 as part of the final 2025 IRP preferred portfolio.[7] Similarly, the resource costs for Wyoming wind are lower than the avoided cost under Schedule 37, though this may reflect the higher value of QF wind generation in Utah, due to differences in generation profiles.

Table 2: Tracking Solar Avoided Cost ($/MWh)

	PDDRR Avoided Cost			***Resource Cost***			***Step Change***		
	Willamette Valley Solar (2032)			***UT Solar***					
	Originally Filed	***Corrected Escalation***	***SLC Capital***	***2029 COD (SLC)***	***2031 COD (SLC)***	***2031 COD (IRP)***	***Corrected Escalation***	***SLC Capital***	***UT Solar 2029 COD (SLC)***
	a	b	c	d	e	f	= b - a	= c - b	= d - c
2025	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	-	-	-
2026	$19.45	$19.45	$19.45	$19.45	$19.45	$19.45	-	-	-
2027	$19.78	$19.78	$19.78	$19.78	$19.78	$19.78	-	-	-
2028	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	-	-	-
2029	$30.40	$30.40	$30.40	$16.59	$30.40	$30.40	-	-	($13.81)
2030	$25.67	$25.67	$25.67	$16.95	$25.67	$25.67	-	-	($8.72)
2031	$24.37	$24.37	$24.37	$18.26	$15.11	$10.76	-	-	($6.11)
2032	**$28.47**	**$31.65**	**$34.54**	$18.66	$15.44	$10.99	$3.18	$2.89	($15.88)
2033	$27.67	$30.94	$33.91	$19.06	$15.78	$11.23	$3.27	$2.97	($14.85)
2034	$29.00	$32.35	$35.40	$19.48	$16.12	$11.48	$3.35	$3.05	($15.92)
2035	$26.17	$29.61	$32.75	$19.90	$16.47	$11.73	$3.45	$3.14	($12.85)
2036	$25.24	$28.79	$32.01	$20.34	$16.83	$11.98	$3.54	$3.22	($11.67)
2037	$23.94	$27.57	$30.87	$20.78	$17.20	$12.24	$3.63	$3.31	($10.09)
2038	$17.89	$21.62	$25.02	$21.24	$17.58	$12.51	$3.73	$3.40	($3.78)
2039	$14.15	$17.99	$21.48	$21.70	$17.96	$12.78	$3.83	$3.49	$0.22
2040	$16.54	$20.47	$24.04	$22.17	$18.35	$13.06	$3.93	$3.58	($1.87)
2041	$18.77	$22.81	$26.49	$22.65	$18.75	$13.35	$4.04	$3.68	($3.83)
2042	$65.66	$69.81	$73.59	$23.15	$19.16	$13.64	$4.15	$3.78	($50.44)
2043	$71.24	$75.49	$79.37	$23.65	$19.58	$13.93	$4.26	$3.88	($55.72)
2044	$62.64	$67.02	$71.01	$24.17	$20.00	$14.24	$4.38	$3.99	($46.84)
2045	$64.01	$68.48	$72.55	$24.70	$20.44	$14.55	$4.47	$4.07	($47.86)
15 Year Levelized Avoided Cost Starting 2027									
	$24.08	$26.07	$27.88	$19.88	$19.59	$16.54	$1.99	$1.81	($8.00)
Nominal Levelized Lifetime Resource Cost:				$21.29	$18.52	$13.18			

[7] See Table 4.

Table 3: Wind Avoided Cost ($/MWh)

	PDDRR Avoided Cost			*Resource Cost*		*Step Change*		
	Wyoming Wind (2028)			*WY Wind*				
	Originally Filed	***Corrected Escalation***	***SLC Capital***	***2028 (SLC)***	***2028 (IRP)***	***Corrected Escalation***	***SLC Capital***	***WY Wind 2028 (SLC)***
	a	b	c	d	e	= b - a	= c - b	= d - c
2025	$38.56	$38.56	$38.56	$38.56	$38.56	-	-	-
2026	$21.25	$21.25	$21.25	$21.25	$21.25	-	-	-
2027	$21.68	$21.68	$21.68	$21.68	$21.68	-	-	-
2028	**$11.58**	**$10.58**	**$12.02**	$13.74	$12.23	($1.01)	$1.45	$1.72
2029	$23.78	$22.75	$24.23	$14.04	$12.50	($1.03)	$1.48	($10.19)
2030	$24.52	$23.47	$24.98	$14.34	$12.77	($1.05)	$1.51	($10.63)
2031	$1.31	$0.24	$1.78	$14.66	$13.05	($1.07)	$1.54	$12.88
2032	$5.81	$4.71	$6.29	$14.97	$13.34	($1.10)	$1.57	$8.69
2033	$2.19	$1.07	$2.68	$15.30	$13.63	($1.12)	$1.61	$12.62
2034	($5.55)	($6.70)	($5.05)	$15.63	$13.92	($1.15)	$1.64	$20.69
2035	$2.90	$1.73	$3.41	$15.98	$14.23	($1.17)	$1.68	$12.57
2036	$14.57	$13.38	$15.09	$16.32	$14.54	($1.20)	$1.72	$1.23
2037	$9.88	$8.66	$10.41	$16.68	$14.85	($1.22)	$1.75	$6.27
2038	$51.74	$50.49	$52.29	$17.04	$15.18	($1.25)	$1.79	($35.24)
2039	$56.45	$55.18	$57.01	$17.41	$15.51	($1.28)	$1.83	($39.59)
2040	$60.00	$58.70	$60.57	$17.79	$15.85	($1.30)	$1.87	($42.77)
2041	$59.49	$58.16	$60.07	$18.18	$16.19	($1.33)	$1.91	($41.89)
2042	$58.10	$56.74	$58.69	$18.58	$16.54	($1.36)	$1.95	($40.11)
2043	$66.08	$64.69	$66.68	$18.98	$16.91	($1.39)	$1.99	($47.70)
2044	$65.64	$64.22	$66.26	$19.40	$17.27	($1.42)	$2.04	($46.86)
2045	$67.07	$65.62	$67.70	$19.82	$17.65	($1.45)	$2.09	($47.88)
15 Year Levelized Avoided Cost Starting 2027								
	$19.60	$18.57	$20.04	$16.14	$14.61	($1.03)	$1.47	($3.91)
Nominal Levelized Lifetime Resource Cost:				$17.35	$15.45			

While the Company agrees that recent events have resulted in uncertainty in resource costs and development risks which may result in higher costs for some projects, the Company does not have definitive information at this time to reach that conclusion, and neither does the City. Rather the Company expects that, unlike an IRP, any resource procurement would result in lower cost opportunities and higher cost opportunities that span a range of costs that well exceed the impact of the City's proposal shown in Table 1.

That said, given the limited magnitude of the changes, as shown in Tables 2 and 3, and the limited magnitude of potential contracts under Schedule 37, the Company does not necessarily oppose the change for the purpose of establishing Schedule 37 pricing at this time.

III. Resource Portfolio Recommendations

The City and WRA both recommend that the portfolio used to develop avoided costs be updated to reflect the most recent modeling assumptions, and that it reflect the UIWC jurisdictional portfolio from the final 2025 IRP. The modeling for the final 2025 IRP incorporated several assumption changes relative to what was used to develop the Utah 2025 IRP portfolio, including:

- Reduced load forecast: removing large new loads that are expected to provide or pay for their necessary resources and transmission;
- Changes to the modeling of Oregon and Washington compliance requirements;
- Changes in the maximum quantity of small-scale resource capacity available for selection in particular locations;
- Changes to the modeling of PTCs approaching the end of the IRP study horizon in 2045; and
- Changes to the assumed allocation of resources among the Company's jurisdictions, as discussed below.

Because of concerns about the availability of transmission between the east and west side of PacifiCorp's system, and the potential disconnect between costs and benefits for situs resources that are distant from the associated customer load, the Company modified how jurisdictional portfolios were used to identify and allocate the resources in the final 2025 IRP preferred portfolio (presented in Chapter 9 of the Utah 2025 IRP). The final UIWC jurisdictional results were used to identify east proxy resources for inclusion in the preferred portfolio and the entirety of east proxy resource selections were allocated to the UIWC jurisdiction, and would be eligible for deferral by Utah QFs under the PDDRR methodology. Similarly, the Washington and Oregon jurisdictional results were used to identify west proxy resources for inclusion in the preferred portfolio and the entirety of west proxy resource selections were allocated to Oregon and Washington, so they would not be eligible for deferral by Utah QFs under the PDDRR methodology. The process used to develop the final preferred portfolio is illustrated in Table 4.

Table 4: Final 2025 IRP – UIWC Jurisdictional and Preferred Portfolio Detail

Final 2025 IRP Table 9.7: UIWC Jurisdictional Total by Resource Type and Year, Installed MW

	Installed Capacity (MW)							
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Expansion Options								
Renewable - Utility Wind	-	-	-	-	306	684	344	-
Renewable - Utility Solar	-	-	-	153	12	79	668	-

Final 2025 IRP Table 9.4: UIWC Allocated Shares by Resource Type and Year, Installed MW

	Installed Capacity (MW)							
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Expansion Options								
Renewable - Utility Wind	-	-	-	-	200	200	344	-
Renewable - Utility Solar	-	-	-	-	-	-	668	-

Final 2025 IRP Table 9.10: Preferred Portfolio (with additional resource detail)

Portfolio Category	2025	2026	2027	2028	2029	2030	2031	2032
East								
Renewable - Utility Solar								
Utility Scale Solar - Bridger	-	-	-	-	-	-	**88 (d)**	-
Utility Scale Solar - Hunter/Huntington	-	-	-	-	-	-	406 (d)	-
Utility Scale Solar - Naughton	-	-	-	-	-	-	100 (d)	-
Utility Scale Solar - Utah South	-	-	-	-	-	-	74 (d)	-
Renewable - Utility Solar Total	**-**	**-**	**-**	**-**	**-**	**-**	**668.0**	**-**
Renewable - Wind								
Utility Scale Wind - Bridger	-	-	-	-	100 (d/Q)	100 (d)	100 (d)	-
Utility Scale Wind - DJ/Wyodak Gen	-	-	-	-	**100 (d/Q)**	100 (d)	244 (d)	-
Renewable - Wind Total	**-**	**-**	**-**	**-**	**200**	**200**	**344**	**-**
West								
Renewable - Utility Solar								
Utility Scale Solar - Central OR	-	-	-	-	38.0	114.7	-	-
Utility Scale Solar - Southern OR	-	-	-	-	-	-	100.0	138.7
Utility Scale Solar - Summer Lake	-	-	-	100.0	100.1	201.9	-	-
Utility Scale Solar - Walla Walla - WA	-	-	-	20.9	41.9	732.2	-	-
Utility Scale Solar - Willamette Valley	-	-	-	-	-	113.7	81.3	100.0
Utility Scale Solar - Yakima	-	-	-	101.4	-	527.6	-	1.0
Renewable - Utility Solar Total	**-**	**-**	**-**	**222.3**	**179.9**	**1,690.1**	**181.3**	**239.7**
Renewable - Wind								
Utility Scale Wind - Central OR	-	-	-	-	-	69.8	0.1	-
Utility Scale Wind - Summer Lake	-	-	-	-	-	401.9	0.1	-
Utility Scale Wind - Walla Walla - WA	-	-	-	20.9	0.1	350.0	-	-
Utility Scale Wind - Willamette Valley	-	-	-	-	593.9	0.1	-	1.0
Utility Scale Wind - Yakima	-	-	-	-	-	430.0	-	-
Renewable - Wind Total	**-**	**-**	**-**	**20.9**	**594.0**	**1,251.8**	**0.2**	**1.0**

The top section of Table 4 shows the resource types and quantities identified in the UIWC jurisdictional portfolio underlying the final 2025 IRP preferred portfolio. The middle section shows the amount of that total allocated to the UIWC jurisdiction (as opposed to Oregon or Washington). The bottom section provides detail on the specific resource locations and the total resource quantities in the final 2025 IRP preferred portfolio. The resource locations are key, and are not apparent until you look at the resource specific detail at the bottom of Table 4. As a result, while solar resources are selected as early as 2028 in the final UIWC jurisdictional portfolio, those solar resources are located on the west side of the system, physically contribute to meeting energy and capacity requirements associated with load on the west side, and are most likely to be used to meet the environmental compliance obligations of Oregon and Washington, particularly given those states' active development of request for proposals (RFPs). PacifiCorp does not have any east-bound transfer capability today, and is expected to get only limited amounts in the future once the Boardman to Hemingway transmission line is in service. PacifiCorp expects the sharing of existing system resources can continue to benefit all of its existing customers, but believes that procuring new resources that are distant from load presents too much risk. Put simply, the reliability benefits of a new resource may be limited to its local area to the extent binding transmission limits are present. Similarly, the energy value of a resource is limited and risks are increased if transmission constraints prevent delivery of the resource to load and market purchases must be used instead.

The City and WRA both recommend that the portfolio represented by the top section of Table 4 be used to set avoided costs, ignoring resources allocated to other jurisdictions and the transmission limits which would prevent delivery of west side resources to the east side of the Company's system and Utah customers. This is somewhat analogous to a Utah utility modeling the entirety of the western interconnect—while the expected development of solar resources in Arizona may influence the cost-effectiveness of resource additions in Utah, that does not mean resources sited in Arizona are necessary or cost-effective for Utah ratepayers. In addition, the preferred portfolio has been the basis for the determination of avoided costs under the PDDRR methodology since it was adopted in Docket No. 12-035-100.[8] Part of the basis for the use of the preferred portfolio is that it reflects the least-cost, least-risk resources.[9] The analysis of the preferred portfolio in an IRP includes evaluating its performance under multiple price-policy scenarios, under a range of stochastic conditions, and under variant conditions (evaluating one-off differences in the portfolio). Yet that level of analysis was not performed on the UIWC full jurisdictional portfolio as it is a preliminary step in the process of developing and selecting the preferred portfolio.

The Company is not opposed to updating to reflect the final 2025 IRP preferred portfolio, in particular because the proxy solar resource from the Utah 2025 IRP is located on the west side of the system, which is disconnected from resource needs and avoided costs in Utah and potentially problematic for the reasons described above. To that end, PacifiCorp intends to present a non-routine update for consideration by parties that reflects the incorporation of the final 2025 IRP preferred portfolio as part of its next Schedule 38 quarterly avoided cost inputs compliance filing, which will occur by the end of September.[10] In the final 2025 IRP preferred portfolio, the first wind resource that would be deferrable by Utah QFs under the PDDRR methodology is located in Wyoming and has a commercial operation date in 2029, as shown by the green highlighted entries in Table 4. The first deferrable solar resources are located in Utah and Wyoming and have commercial operation dates in 2031, as shown by the orange highlighted entries in Table 4. All of the wind and solar proxy resource selections in the final 2025 IRP preferred portfolio were assumed to be eligible for PTCs, and there is not currently any evidence to indicate that those resources would remain cost-effective for Utah customers in the absence of PTCs. A one-year acceleration of the

[8] *E.g.,* Docket No. 12-025-100, Order (Aug. 16, 2023).
[9] *Id.,* at 41-42.
[10] See Docket No. 25-035-30.

2031 solar resources selections might be a reasonable adjustment relative to the final 2025 IRP preferred portfolio as filed, but likely would not change the avoided cost results significantly.

The City also recommends that the Natrium advanced nuclear demonstration project be excluded from the preferred portfolio for the determination of avoided costs. In general, the removal of a zero-variable cost resource would result in the dispatch of resources with higher marginal cost than the resources that would have been dispatched when that zero-variable cost was included, resulting in higher avoided costs. The 2025 IRP included a variant scenario that excluded the Natrium project, and in the absence of Natrium, included a variety of wind and solar resource additions among other changes. The addition of those wind and solar resources would tend to offset the impact of removing Natrium, though the impact would vary from hour to hour. To the extent that a QF's generation profile was correlated with the wind or solar resources that would offset the removal of the Natrium project, the net impact would likely be a reduction in avoided costs as the weighted average resource impacts in the hours when wind or solar were available would be a larger portion of the avoided costs. In any event, a one-off removal of the Natrium project without considering alternative resource supply, as proposed by the City, would not reflect a least-cost, least-risk portfolio. In addition, the Company recently executed a PPA for the Natrium project (a.k.a. Kemmerer Power Station Unit 1) which will enable the commercial demonstration of the technology while managing the risks faced by the Company's retail customers. The Company will shortly be filing for approval of the PPA as a significant energy resource consistent with Utah Code Ann. § 54-17-302.

IV. <u>Other Recommendations</u>

First, WRA requests that avoided cost prices not be updated until stakeholders have had the opportunity to comment on the 2025 IRP, and that the timing of future avoided cost updates similarly be delayed to allow stakeholder review of a filed IRP. Per the Commission's scheduling order in Docket No 25-035-22, parties will provide written comments on the 2025 IRP by September 26, 2025 and reply comments by November 25, 2025.

Rocky Mountain Power notes that this recommendation deviates from the current Commission-approved approach. The Company prepares Schedule 37 pricing using the same assumptions and methodology applicable to larger, non-standard QFs under Schedule 38. The inclusion of assumptions from the most recently filed IRP or IRP Update is identified as a "Routine Update" in the procedures for Schedule 38 avoided cost input changes adopted by the Commission in Docket No. 14-035-140. Per the approved procedures, Routine Updates are incorporated into avoided cost pricing without prior notification or agreement from parties. With the filing of the 2025 IRP on March 31, 2025, the approved procedures require that the 2025 IRP be reflected in all indicative avoided cost pricing provided to Schedule 38 QFs starting on April 1, 2025. Delaying the applicability of avoided cost pricing changes to September or November 2025, as proposed by WRA, would be a significant deviation from those approved procedures. That said, the Company recognizes that circumstances are different for Schedule 37 and Schedule 38. Following the provision of indicative pricing to a Schedule 38 QF, the developer would negotiate and execute a power purchase agreement which would be submitted to the Commission for approval. The Commission ultimately determines whether the prices, terms and conditions of the PPA are consistent with applicable state and federal laws, relevant Commission orders, and Schedule 38, concluding that PPAs meeting those requirements are just and reasonable and in the public interest. The docket opened to consider approval of each Schedule 38 PPA provides an opportunity for parties to present evidence that the prices and terms in a PPA do not meet those requirements. To the extent evidence indicates the Schedule 38 methodology does not result in just and reasonable results in a particular instance, the Commission is empowered to make appropriate modifications to uphold its responsibilities under PURPA.

For Schedule 37 pricing, the analogous opportunity for parties to present evidence is the present docket. With that in mind, the Company does not oppose the parties' ability to present evidence in this docket or to request an extension of time to present evidence in this docket. The Company opposes WRA's indeterminate proposal to pause consideration of the current docket pending further consideration of the 2025 IRP in Docket No. 25-035-22, and to require the same lag in Schedule 37 pricing updates going forward. If future information in Docket 25-035-22 has a bearing on avoided costs, the Schedule 38 procedures already include quarterly filing by the Company to reflect new information and consideration of changes proposed by parties. The Commission's approval of any substantive change to Schedule 38 could be accompanied by a requirement for a Schedule 37 compliance filing outside of the annual update process.

Second, WRA requests that QFs always be allowed to retain any RECs they produce, even if they are compensated based on the costs of a REC-generating proxy resource. That conflicts with the current Commission established methodology from dockets 17-035-T07 and 17-035-37.[11] During the portion of a QF's contract term in which it defers or avoids a renewable resource, the ratepayers who pay for the QF contract are entitled to the benefits of the RECs PacifiCorp would have received from the deferred or avoided resource. During other periods, when a QF's avoided capacity costs are not based on the costs of a renewable resource, the QF is entitled to the RECs associated with its output. This treatment remains consistent with the PURPA ratepayer indifference standard, notwithstanding the lack of assumed REC benefits as part of portfolio development in the 2025 IRP, benefits which the Company would seek to maximize on behalf of customers but which depend on future demand from REC purchasers that is uncertain. The Commission should deny this request.

V. <u>Conclusion</u>

The Company remains committed to working with the Division, the Office of Consumer Services, the City, WRA, and other interested parties to maintain accurate and up-to-date cost pricing within Schedule 37. The Company respectfully requests the Commission issue an order approving proposed avoided costs incorporating the changes described herein. The Company is ready to prepare a compliance filing incorporating these or alternative assumptions or to provide additional supporting information as directed by the Commission.

[11] Consolidated Docket Nos. 17-035-T07 and 17-035-37, Order, at 7-8 (Jan. 23, 2018).

Sincerely,

Zachary Rogala
Assistant General Counsel
PacifiCorp

CERTIFICATE OF SERVICE

Docket No. 25-035-T03

I hereby certify that on September 3, 2025, a true and correct copy of the foregoing was served by electronic mail to the following:

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