ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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October 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. 25-035-30
Rocky Mountain Power's 2025 Avoided Cost Input Changes Quarterly Compliance Filing
Rocky Mountain Power Comments

On May 7, 2025, Rocky Mountain Power (the "Company") filed its quarterly compliance filing for avoided cost input changes. On May 27, 2025, the Division of Public Utilities ("Division") and Salt Lake City Corporation ("City") filed comments. In accordance with the Commission's August 1, 2025, Scheduling Order, Rocky Mountain Power submits its comments addressing the recommendations of the Division and the City.

Summary of Comments

The Division's comments recommend that the Utah Public Service Commission ("Commission") acknowledge the filing and state that the filing complies with the appropriate orders from the Commission. The comments also recommend that the Commission direct the Company to "explain the large decrease in pricing and correct the non-material mistakes in Appendices B.1, B.2, and B.3 . . ."[1]

The City's comments request that the Commission suspend the Company's proposed revisions and consider a new methodology for calculating avoided costs to better "reflect the lack of equity investment in the Company by its owner for new generation and the unprecedented uncertainty in power plant capital costs."[2]

Comments

The Company confirms that, as noted by the Division and the City, outdated descriptions were included in Appendices B.1, B.2, and B.3 and that the calculations were performed using the

[1] Utah Division of Public Utilities. Docket No. 25-035-30, Action Request Response (May 27, 2025).
[2] Salt Lake City Corporation. Docket No. 25-035-30, Comments.

intended inputs, so that no change in the reported values is necessary.[3] Corrected versions of these appendices are being provided with these comments.

Both the Division and the City requested additional explanation of the large decrease in avoided cost pricing in the Company's May 7, 2025, filing. The majority of the change is associated with the incorporation of the Utah 2025 Integrated Resource Plan ("IRP"), which impacted a number of assumptions, including proxy resource selections, proxy resource costs, state policy compliance selections, and an updated load forecast.

Additional detail on the change in baseload qualifying facility ("QF") prices is included as part of Appendix C in the Company's May 7, 2025, compliance filing. The biggest single contributor to the change in baseload QF prices is the removal of the 2023 IRP Update capacity value based on the costs of a natural gas simple cycle combustion turbine ("SCCT") starting in 2029. The Utah 2025 IRP preferred portfolio did not include any proxy thermal resource selections, so the capacity value dropped to zero. The cost of the SCCT amounted to $13.38/MWh in 2029, or a levelized value of $10.75/MWh for a fifteen-year contract term starting in 2026. Under the Partial Displacement Differential Revenue Requirement ("PDDRR") methodology, the compensation to the baseload QF is net of the energy benefits of the displaced SCCT, though after accounting for fuel costs this offsets only a small portion of the SCCT cost. In total, the SCCT deferral accounts for roughly half of the overall $21.35/MWh reduction in baseload QF avoided costs as a result of the Utah 2025 IRP.

Another major change that impacts baseload resource avoided cost pricing is the load forecast. The Utah 2025 IRP load forecast was lower than the 2023 IRP Update load forecast by an average of nearly 700 megawatts per hour. A load forecast reduction is analogous to having a very large queue of potential QFs. The potential QF queue used in the Schedule 38 process is intended to ensure that the cost savings for one QF do not get double counted as successive QFs are added. As each QF is added, production cost modeling backs down the remaining resource with highest cost, but from a pool of lower and lower cost alternatives. In the same way, when 700 megawatts of load are removed, higher cost resources are called upon less frequently and avoided costs fall.

Finally, the 2025 IRP includes two modifications to market purchases that impact baseload avoided cost pricing, related to market purchase limits and daily market prices. In the 2023 IRP Update, market purchases are restricted to 1,000 megawatts in all hours throughout the summer season (June-September). In the 2025 IRP, summer market purchases are restricted to zero, but only between 4:00 p.m. and 12:00 a.m. on PacifiCorp's top five load days in each month. During other periods, PacifiCorp expects plentiful market supply will be available. For an example of why this is reasonable, consider that the California Independent System Operator ("CAISO") hit an all-time peak load on September 6, 2022. The peak load of 52,061 megawatts occurred just before

[3] Utah Division of Public Utilities. Docket No. 25-035-30, Action Request Response, fn. 4 (May 27, 2025) ("The Division assumes RMP meant for Appendix B.1, B.2, and B.3, column headings (F6, G6, and H6), to be the difference between UT 2025.Q1 and UT 2024.Q4 versus UT 2024.Q3. The ensuing values match UT 2024.Q4. Secondly, the Appendices reference (Cell B27 on Appendix Tab) interest rate of 6.69%. The Division's analysis verifies the current 6.38% discount and 2.18% inflation rate were used in the calculations.").

5:00 p.m., and was aided by the presence of over 10,000 megawatts of utility-scale solar generation at that time.[4] As solar output was declining, CAISO issued public notices to curtail load and moved to its highest alert level, where increases in load or losses of generation are countered by curtailment of firm load (i.e. rotating outages). Measurable reductions in load occurred after the alert, and CAISO reported a net load peak (load net of solar and wind generation) of 45,141 megawatts at just before 7:00 p.m. by which time solar output had dropped below 500 megawatts. Some resources that helped cover the net load peak at 7:00 p.m. were available during the gross load peak at 5:00 p.m. but had not yet been deployed since solar output was still covering a significant portion of the total demand. Allowing market purchases until 4:00 p.m. recognizes that economic supply conditions are likely to prevail while the sun is relatively high in the sky, particularly during the summer. By allowing market purchases on most days, particularly during relatively low-cost daylight hours, the 2025 IRP can use market purchases and reduce the need to dispatch higher cost generating resources, resulting in lower avoided costs during a significant number of hours.

The second market-related modification in the 2025 IRP is the incorporation of historical relationships between daily prices, loads, and resource supply to better account for the impacts of supply and demand. In past IRPs a single daily pattern of market prices was repeated on every weekday in a given month. A separate pattern was used for Saturdays, and a further pattern for each Sunday and holiday. Market price volatility was captured as a part of stochastic analysis, but was not reflected in the normalized modeling inputs, including those reflected under the Schedule 38 avoided cost pricing methodology. In the 2025 IRP, PacifiCorp developed daily pricing variation that reflects the historical weather conditions underlying the load forecast. While the average price over the month is unchanged, prices on individual days vary above and below the average level. When PacifiCorp's loads are high, regional demand tends to be high and market prices tend to rise, but PacifiCorp's loads are only one of many influences on prices. In addition to regional loads, market prices are also impacted by renewable resource output and the 2025 IRP uses wind and solar shapes that are also based on weather conditions from the same historical days as the load forecast, keeping all of these inputs in alignment. PacifiCorp has a range of generating resources that can be deployed as load increases and market prices rise, but the daily variation in market pricing introduced in the 2025 IRP results in many opportunities each month to use lower cost market purchases that were not available in prior modeling. As a result, while higher market prices can contribute to higher avoided costs on some days, costs are frequently limited by the marginal cost of PacifiCorp's thermal fleet under those conditions, rather than market prices, whereas market purchases are more likely to be the marginal resource on days with lower market prices. Examples that illustrate these relationships are provided in Figures 1 and 2 below.

[4] https://www.caiso.com/documents/summermarketperformancereportforseptember2022.pdf

Figure 1 -- Historical Market Prices vs Load, July 2023[5]

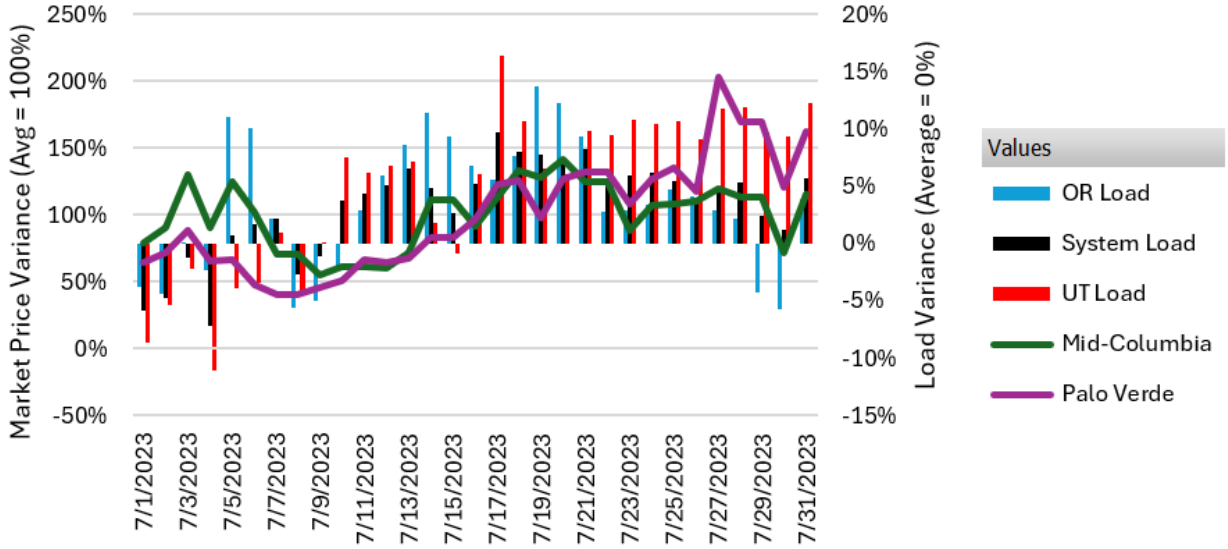
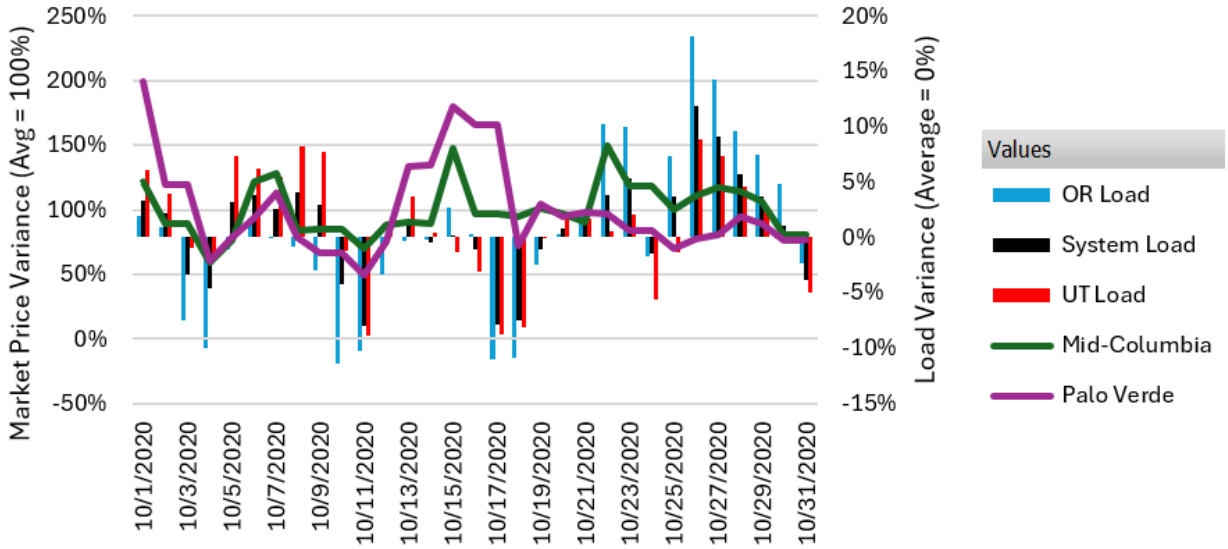


Figure 2 – Historical Market Prices vs Load, October 2020[6]



While the market purchase modifications from the 2025 IRP influence the avoided cost pricing for solar and wind, the largest factor for these resources is the assumed cost of the proxy resources displaced under the PDDRR methodology. The 2023 IRP Update retained the resource cost assumptions from the 2023 IRP, which included costs through 2028 that were based on recent offers PacifiCorp had received as of the summer of 2022, and then transitioned to long-term cost estimates from the National Renewable Energy Laboratory's ("NREL") 2022 Annual Technology

[5] PacifiCorp's Utah 2025 IRP. Volume II. Appendix H (Stochastics). Figure H.5. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_IRP_Vol_2_Utah.pdf

[6] *Id.* Figure H.6.

Baseline ("ATB"). To increase transparency, the 2025 IRP used resource cost assumptions from the 2024 NREL ATB throughout the IRP study horizon. PacifiCorp's September 30, 2025, compliance filing includes a correction to the cost escalation rates applied to wind and solar, resulting in slightly higher solar costs and slightly lower wind costs.[7] That filing also included a non-routine update with Schedule 38 avoided costs calculated using the Final 2025 IRP preferred portfolio. A summary of the wind and solar resource costs used in recent Schedule 38 compliance filings is provided in Table 1. The costs for both wind and solar dropped by more than thirty percent between the 2023 IRP Update and the 2025 IRP.

Table 1 – Proxy Wind and Solar Resource Costs

Avoided Solar Resource Cost Assumptions	2024.Q4	2025.Q1	2025.Q2	Non-routine
	2023 IRP Update			
		2023 IRP Update	Utah 2025 IRP	Utah 2025 IRP	Final 2025 IRP
Capital Cost ($/kw)	UT PV	Small-Scale OR PV	OR PV	Total PV	OR PV	OR PV	West WY PV
2027	$1,541	$2,061	$1,668	$1,885	$1,188	$1,319	$1,217
…					…	…	…
2031					$1,023	$1,188	$1,121
2032					$1,029	$1,150	
% reduction in 2027 resource costs					-37%	-30%	-35%

Avoided Wind Resource Cost Assumptions	2024.Q4	2025.Q1	2025.Q2	Non-routine
	2023 IRP Update			
		2023 IRP Update	Utah 2025 IRP	Utah 2025 IRP	Final 2025 IRP
Capital Cost ($/kw)	West WY WD	East WY WD	Total WD	East WY WD	East WY WD	East WY WD
2027	$2,198	$2,119	$2,181	$1,439	$1,395	$1,395
2028				$1,455	$1,395	$1,395
2029						$1,394
% reduction in 2027 resource costs				-34%	-36%	-36%

Deferred Proxy Resources

Other data points for comparison

[7] *See* 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).

If PacifiCorp's May 7, 2025, quarterly update to incorporate the 2025 IRP had held capital cost assumptions unchanged at the previous values from the 2023 IRP Update preferred portfolio, avoided costs for solar would have been essentially unchanged, i.e. all other impacts related to the 2025 IRP would have largely cancelled out. Similarly, capital cost differences represented around 60% of the change in wind avoided costs related to the 2025 IRP, with the remainder attributable to balancing out the generation profile differences between the Utah wind QF and the Wyoming wind proxy. For instance, the Utah wind QF has lower output in the winter, which coincides with low output from Utah solar resources. The difference in output between the two profiles is impacted by updated load and market assumptions in much the same manner as described for baseload QFs. The step changes in recent wind and solar avoided costs are identified in Table 2 below.

Table 2 – Comparison of Recent Wind and Solar Avoided Costs

		Indicative Solar QF Avoided Cost, $/MWh					
	Proposed Term:	**2025 - 2039**		**2026 - 2040**		**2027 - 2041**	
	2024.Q4	$32.83	-$0.74	$35.56	+$0.37	$38.42	+$1.02
	2025.Q1 (23IRP Capital)	**$33.58**	**+$9.93**	**$35.19**	**+$11.75**	**$37.41**	**+$13.73**
	2025.Q1 As Filed	$23.65		$23.44		$23.68	
Routine update	OFPC June 2025	$23.98	+$0.33	$23.86	+$0.42	$23.92	+$0.24
Routine update	Corrected Escalation	$25.43	+$1.45	$25.57	+$1.71	$25.91	+$1.99
Non-routine update	*Final 2025 IRP*	*$5.94*	*-$19.49*	*$3.58*	*-$21.99*	*$3.72*	*-$22.19*

		Indicative Wind QF Avoided Cost, $/MWh					
	Proposed Term:	**2025 - 2039**		**2026 - 2040**		**2027 - 2041**	
	2024.Q4	$32.83	$6.88	$35.56	$7.27	$38.42	$7.53
	2025.Q1 (23IRP Capital)	**$25.95**	**$9.74**	**$28.29**	**$11.02**	**$30.89**	**$12.39**
	2025.Q1 As Filed	$16.21		$17.27		$18.50	
Routine update	OFPC June 2025	$16.66	+$0.45	$17.81	+$0.54	$18.82	+$0.32
Routine update	Corrected Escalation	$15.85	-$0.81	$16.90	-$0.91	$17.80	-$1.02
Non-routine update	*Final 2025 IRP*	*$5.40*	*-$10.45*	*$5.44*	*-$11.46*	*$5.10*	*-$12.70*

The City's May 27, 2025, comments raise the question of whether the thermal QF should partially displace the Natrium nuclear resource included in the Utah 2025 IRP preferred portfolio in 2030. It would be reasonable for a QF to displace a cost-effective nuclear resource if it was based on proxy nuclear resource costs, which is not the case for Natrium. The inclusion of Natrium in the 2025 IRP was based on PacifiCorp's ongoing negotiations for project output which would protect customers from the risks associated with a first-of-a-kind resource. The Company recently executed a power purchase agreement ("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 a request

for an order under Utah Code Ann. § 54-17-501 waiving the solicitation requirement and a request for an order under Utah Code Ann. § 54-17-302 approving the Company's "significant energy resource decision" to enter into the PPA.

The City's comments also raise several other issues, including the Company's representation of production tax credits, the appropriate discount rate, and the validity of capital costs. Each of these assumptions is consistent with the inputs to the 2025 IRP and it is uncertain how the cost effectiveness of the resources in the preferred portfolio would have been impacted by these changes. A relatively comprehensive update to input assumptions will be captured in PacifiCorp's 2025 IRP Update, which is scheduled to be filed by the end of March 2026. The City also questions whether the ownership of renewable energy credits ("RECs") should change if future resources were to be procured through a PPA. PacifiCorp's 2020 All-Source Request for Proposals resulted in a number of wind and solar PPAs, all of which included bundled RECs transferred to the Company for the benefit of customers, so procurement via a PPA certainly does not preclude the Company from taking ownership of RECs. The City's proposal also conflicts with the current Commission established methodology from dockets 17-035-T07 and 17-035-37.[8] During the portion of a QF contract term in which it defers or avoids a renewable resource, the retail customers 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 QF 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 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.

Conclusion

The Company remains committed to working with the Division, the City, and other interested parties to maintain accurate and up-to-date cost pricing within Schedule 38. The Company believes that the most up-to-date inputs should be used in avoided costs, and hopes that parties will consider and comment on its recently filed proposal to update to the Final 2025 IRP preferred portfolio, included as a Non-Routine Update in its September 30, 2025 quarterly compliance filing as part of this docket.[9] The Company also looks forward to reviewing any concrete input changes proposed by parties as part of their comments.

Sincerely,

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[8] Consolidated Docket Nos. 17-035-T07 and 17-035-37, Order, at 7-8 (Jan. 23, 2018).
[9] Docket No. 25-035-30, Rocky Mountain Power's Quarterly Compliance Filing – 2025.Q2 Avoided Cost Input Changes (Sep. 30, 2025).

CERTIFICATE OF SERVICE

Docket No. 25-035-30

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

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