Rocky Mountain Power
Docket No. 26-035-20
Witness: Shelley E. McCoy

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Shelley E. McCoy

April 2026

I. INTRODUCTION

Q. Please state your name, business address and present position with PacifiCorp, d/b/a Rocky Mountain Power.

A. My name is Shelley E. McCoy, and my business address is 825 NE Multnomah Street, Suite 2000, Portland OR 97232. I am currently employed as the Director of Revenue Requirement at PacifiCorp.

II. QUALIFICATIONS

Q. Briefly describe your education and professional background.

A. I earned a Bachelor of Science degree in Accounting from Portland State University in 1990. In addition to my formal education, I have attended several utility accounting, ratemaking, and leadership seminars and courses. I have been employed by PacifiCorp since November 1996. My past responsibilities have included general and regulatory accounting, budgeting, forecasting, and reporting. I assumed my current position in November 2022.

Q. What are your responsibilities as Director of Revenue Requirement?

A. My primary responsibilities include overseeing the calculation and reporting of PacifiCorp's regulated earnings or revenue requirement, ensuring that the inter-jurisdictional cost-allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which PacifiCorp operates.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in multiple dockets before the Utah, Oregon, California, Idaho, Washington, and Wyoming public utility commissions.

III. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports PacifiCorp's Application for Approval and Report of the Sale of Washington Service Area and an Accounting Order to Gem Sub LLC ("Gem"), an affiliate of Portland General Electric Company. Specifically, my testimony provides details on:

- The estimated non-net power cost ("NPC") revenue requirement impact of the sale prior to the sharing of the gain associated with the goodwill value of the business;
- The removal of balances and expenses from revenue requirement associated with the sale;
- The inclusion of incremental coal plant accumulated depreciation and decommissioning balances collected from Washington customers in the revised revenue requirement; and
- The calculation of updated allocation factors after the removal of Washington.

IV. ESTIMATED REVENUE REQUIREMENT IMPACT

Q. What assets is PacifiCorp selling?

A. As identified in PacifiCorp's application and the direct testimony of PacifiCorp witnesses Joelle R. Steward and Nikki L. Kobliha, PacifiCorp is selling its Washington service area and certain Washington-based assets ("Service Area Transfer"). These assets include the Chehalis plant, Goodnoe Hills Wind Farm, Marengo I and II Wind Farms, and certain Washington-based transmission and distribution assets.

Q. Are these assets used to serve Utah customers and included in Utah rates?

A. Not all of the assets are used to serve Utah customers. The Chehalis plant, Goodnoe Hills and Marengo wind farms and the transmission assets are used to serve Utah customers, and an allocation of these resources is included in Utah customer rates. The

Washington distribution assets are only used to serve Washington customers and are therefore not included in Utah customer rates.

Q. What is the estimated non-NPC revenue requirement impact of the proposed Service Area Transfer?

A. As shown in Table 1, the overall impact to Utah's non-NPC revenue requirement is estimated to be an increase of $20.2 million, prior to the consideration of other elements such as the proposed customer rate credits. My Exhibit RMP___(SEM-1) and the supporting workpaper provide the details of the calculations below. Please see Ms. Steward's testimony for the full impact of the sale.

Table 1 – Non-NPC Revenue Requirement Impact

	Transition Period		Post-Transition Period	
($millions)	Total Company	Utah Allocated	Total Company	Utah Allocated
Production	$ 14.0	$ 6.8	$ 14.0	$ 6.8
Transmission	25.4	12.4	25.4	12.4
Distribution	3.0	1.5	3.0	1.5
General & Other	23.2	11.2	23.2	11.2
Total before new revenues & credits	65.6	31.9	65.6	31.9
New wheeling revenues	(23.9)	(11.7)	(13.7)	(6.7)
Estimated Non-NPC Revenue Requirement	**$ 41.7**	**$ 20.2**	**$ 51.9**	**$ 25.2**

Q. Please describe the main elements of Table 1.

A. The revenue requirement increase is broken out by major function. The Production function includes the reallocation of costs of all of PacifiCorp's remaining generation plants, excluding the cost of fuel. The Transmission function reflects the reallocation of PacifiCorp's transmission system, which is almost entirely offset by new wheeling revenues from the transaction. The Distribution function reflects the reallocation of

common costs such as management, engineering, safety and wildfire mitigation that supports distribution operations in all states. The General & Other function includes administrative and general costs, customer service, support costs and property taxes for the business. Not included in Table 1 or in the estimated revenue requirement impact is the change in the blended state tax rate described by Ms. Kobliha. The change in the blended tax rate will be included in future general rate cases and results of operations filings. In addition to a recalculation of the revenue requirement, PacifiCorp will also be collecting new wheeling revenues from new transmission service agreements as described in the direct testimony of PacifiCorp witness Michael G. Wilding. These new transmission service agreements are expected to provide $23.9 million total company, or $11.7 million Utah allocated, in new wheeling revenues during the transition period, and $13.7 million total company, $6.7 million Utah allocated, post transition period.

Q. How was the non-NPC revenue requirement impact of the Service Area Transfer estimated?

A. To estimate the impact, the total company revenue requirement for 2024[1] was compared to the total company revenue requirement after removing expenses and rate base balances associated with the Service Area Transfer. The revised revenue requirement was allocated using updated allocation factors that exclude Washington. The difference between the two amounts for Utah is the estimated revenue requirement impact.

[1] Final allocation factors and regulatory balances for 2025 were not available at the time the analysis was performed.

Q. Please describe the process used for developing the estimate.

A. Starting with actual accounting data for calendar year 2024,[2] PacifiCorp identified all components of non-NPC revenue requirement that will be removed by the sale of the Washington service area and the associated assets. This includes electric plant in service, accumulated depreciation, accumulated deferred income tax, operations and maintenance expense, depreciation and amortization expense, property taxes and the Washington public utility tax. Additionally, Washington's allocation of wildfire liability accruals, legal expenses and liability insurance premiums were removed, as those costs will not be re-allocated to the other five states. Finally, Washington's incremental accumulated depreciation and decommissioning balances for the Jim Bridger and Colstrip generation plants were added in to reflect the costs for these two generation plants paid for by Washington customers that will be reallocated with the other plant balances. After making these adjustments, revenues, expenses and rate base were reallocated to the remaining five states using updated allocation factors, and then a revenue requirement estimate was calculated for each state.

Q. What are the Washington incremental accumulated depreciation and decommissioning balances?

A. Under Washington's Clean Energy Transformation Act the costs of coal-fired generation, with the exception of decommissioning, are not allowed in Washington customer rates past 2025. Therefore, the depreciable lives for the Jim Bridger and Colstrip coal-fired units were set to 2025 for PacifiCorp's Washington customers. As a result, the Washington system allocation under the 2020 PacifiCorp

[2] Rate base was calculated using period ending December 31, 2024.

Inter-Jurisdictional Cost Allocation Protocol ("2020 Protocol") approximately eight percent of Jim Bridger Units 3 and 4 and the Colstrip plant are fully depreciated. This additional accumulated depreciation balance is included in the reallocation of plant balances to the other five states.

In addition to the incremental accumulated depreciation, Washington customers have been paying incremental decommissioning costs for the Jim Bridger and Colstrip plants based on estimates from the Kiewit Studies filed in PacifiCorp's 2018 Depreciation Study.[3] This balance, which is a rate base deduction, has also been reallocated as part of the generation plant reallocation. The collection of decommissioning estimates will continue through 2030. After the Service Area Transfer is complete, Gem will adopt PacifiCorp's tariffs and will remit to PacifiCorp on a quarterly basis amounts collected under Washington Schedule 92, Temporary Coal Cost Adjustment. These additional collections for decommissioning will be added to the existing balances and included in the future allocation of generation rate base.

Q. Were the lives of PacifiCorp's other coal units accelerated for Washington?

A. No. Under Washington's approved allocation methodologies, the West Control Area Inter-Jurisdictional Allocation Methodology followed by the Washington Interjurisdictional Allocation Methodology, Jim Bridger and Colstrip were the only two coal-fired plants included in Washington rates. Therefore, the lives of the other coal plants were not accelerated for Washington rates.

[3] *Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021*, Docket No. 18-035-36, Application (Sep. 11, 2018).

Q. Given that Washington customers did not pay for these other coal plants, did this affect the recording of depreciation on PacifiCorp's books?

A. No. PacifiCorp records depreciation of its assets on a total company basis using the approved depreciation rates from depreciation studies filed with the state commissions in the states where PacifiCorp serves retail customers. The depreciation expense is not impacted by allocation methodologies or even variations in allocation percentages between rate cases. Any differentiation in depreciable lives, such as Washington's lives for the Bridger and Colstrip units, is then recorded as an increment to the system depreciation expense based on the applicable allocation factor under the 2020 Protocol.

Q. How were the allocation factors revised for this estimate?

A. For each of the system allocation factors, such as System Generation or Customer Number, the Washington component was removed from the six-state allocation factors. The remaining five-state allocation factors were then proportionately recalculated to reflect five-state allocations after the Service Area Transfer. This change in the allocation factors reflects an increased percentage of remaining resources allocated to each state based on the algebraic formulas in the 2020 Protocol.

Q. What rate of return assumptions were relied upon in the revenue requirement calculations?

A. To calculate the return-on-rate base component of revenue requirement, PacifiCorp used a five-quarter average 2024 actual capital structure and a 9.55 percent average return on equity. The actual revenue requirement impact will be dependent on each state's authorized cost of capital.

Q. When will the actual Utah impact of the Service Area Transfer be known?

A. A specific and more detailed calculation for the revenue requirement impact for Utah will be included in PacifiCorp's next general rate case.

V. ALLOCATION FACTORS

Q. What allocation methodology was assumed in the calculation of allocation factors?

A. Allocation factors were calculated in accordance with the 2020 Protocol. While the 2020 Protocol expired at the end of 2025, it is the most recent allocation methodology approved by the Public Service Commission of Utah ("Commission") and used to establish current rates. Therefore, it is a logical option for evaluating impacts of the Service Area Transfer.

Q. How were the allocation factors adjusted for the Service Area Transfer?

A. Consistent with the accounting data, PacifiCorp began with the 2024 normalized allocation factors used in PacifiCorp's December 2024 Results of Operations report filed with the Commission.[4] Next the Washington percentages were set to zero, and the remaining percentages were proportionately recalculated for the other jurisdictions. This approach preserves the dynamic nature of the allocation factors established under the 2020 Protocol and reflects how those factors naturally shift when underlying data—such as energy usage—changes for one or more states.

Q. What were the changes to the updated allocation factors?

A. Table 2 shows a comparison of key allocation factors for the original 2024 data and the revised calculations without Washington for each jurisdiction. These percentages are a snapshot in time and will fluctuate with the underlying data but provide a reasonable

[4] *PacifiCorp's Financial Reports 2025*, Docket No. 25-035-04, Rocky Mountain Power's 2024 Results of Operations (Apr. 28, 2025).

expectation of the impact of removing Washington from the calculation of allocation factors.

Table 2 - Comparison of Allocation Factors

Factor Description	Factor	CA	OR	WA	UT	ID	WY	FERC	Total
System Generation	SG	1.32%	26.16%	7.47%	45.12%	6.04%	13.86%	0.02%	100.00%
System Generation - Revised	SG	1.43%	28.27%	0.00%	48.77%	6.53%	14.98%	0.02%	100.00%
System Energy	SE	1.30%	25.20%	7.22%	44.58%	6.24%	15.44%	0.02%	100.00%
System Energy - Revised	SE	1.40%	27.16%	0.00%	48.04%	6.73%	16.64%	0.02%	100.00%
Customer Number	CN	2.22%	30.30%	6.61%	49.60%	4.29%	6.98%	0.00%	100.00%
Customer Number - Revised	CN	2.37%	32.44%	0.00%	53.11%	4.60%	7.48%	0.00%	100.00%
System Overhead	SO	2.49%	27.30%	7.37%	44.33%	5.75%	12.75%	0.01%	100.00%
System Overhead - Revised	SO	2.69%	29.47%	0.00%	47.85%	6.21%	13.76%	0.02%	100.00%

VI. CONCLUSION

Q. What is your recommendation for the Commission?

A. I recommend that the Commission find Utah customers will not be harmed by the sale of the Washington-based generation and transmission assets included in the Service Area Transfer and approve the asset sale.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(SEM-1)
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Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Non-Net Power Cost Revenue Requirement Impact
of Washington Sale

April 2026

Rocky Mountain Power
Application for Service Area Transfer
Estimated Revenue Requirement Change Due to Washington Sale
After Adjustments
2024 Data

		Adjustments						
Function	Total Impact	Wildfire Liability Costs	Liability Insurance Costs	Est. WA Taxes No Longer Incurred	WA Incr. Accum Depr/Decom	Impact Before New Wheeling Revenues	New Wheeling Revenues	Adjusted Impact
Production	20,792,817				(6,756,829)	14,035,988		14,035,988
Transmission	25,328,046					25,328,046	(23,913,389)	1,414,657
Distribution	3,014,401					3,014,401		3,014,401
General	81,072,605	(27,748,938)	(7,457,363)	(22,640,385)		23,225,919		23,225,919
Total	130,207,868	(27,748,938)	(7,457,363)	(22,640,385)	(6,756,829)	65,604,353	(23,913,389)	41,690,964

	State Allocations						
Function	CA	OR	UT	ID	WY	FERC	Total
Production	200,982	3,944,601	6,827,869	920,847	2,138,499	3,189	14,035,988
Transmission	20,247	401,360	690,798	92,148	209,776	328	1,414,657
Distribution	45,908	861,536	1,478,254	192,702	435,358	641	3,014,401
General	599,424	6,826,162	11,246,906	1,425,210	3,124,589	3,627	23,225,919
Total	866,562	12,033,660	20,243,827	2,630,907	5,908,223	7,785	41,690,964