Rocky Mountain Power
Docket No. 26-035-20
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Ramon J. Mitchell

April 2026

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Ramon J. Mitchell, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Managing Director, Energy Supply Management Finance and Net Power Costs.

Q. Please describe your education and professional experience.

A. I received a Master of Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by PacifiCorp in 2015 and during my time at PacifiCorp, I have held various positions in the regulation, merchant, transmission, and finance departments. After a brief departure from PacifiCorp, in 2022 I returned and now serve as Managing Director, Energy Supply Management Finance and Net Power Costs. With respect to this proceeding, I am responsible for overseeing the power costs analysis of PacifiCorp's sale of its Washington service area and select Washington-based assets ("Service Area Transfer"), inclusive of the models and assumptions used in this analysis.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Public Service Commission of Utah ("Commission"), as well as commissions in California, Idaho, Oregon, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the overall purpose of your testimony?

A. My analysis demonstrates that the Service Area Transfer decreases the average unit cost of power for PacifiCorp's remaining customers. Specifically, the unit cost of power decreases in the 2030 Forward Period, and this structural benefit is independently confirmed across 48 months of actual historical system conditions.

In this testimony, I present a transparent, verifiable analysis of the power costs impacts resulting from the proposed Service Area Transfer to an affiliate of Portland General Electric Company ("PGE"), referred to as "Gem" for the purposes of this testimony. My testimony explains the operational drivers that change PacifiCorp's power costs, details the physical energy balance versus the financial cost of energy, and quantifies the resulting benefits to PacifiCorp's remaining customers across all analyzed periods.

My power costs analysis supports the Service Area Transfer, demonstrating that under forward-looking system normal conditions,[1] the transaction leaves remaining customers strictly better off under a diverse spectrum of market, load, and generation conditions. My analysis is further supported by historical data across 48 months of actual system conditions from January 2022 through December 2025, which confirms that the structural benefit continues to persist under a diverse spectrum of conditions, with observed wholesale market prices ranging from $36 to $248 per megawatt-hour.

[1] Post-2030, post-Service Area Transfer transitional agreements, post-sale rate credits.

III. DEFINITION OF POWER COSTS

Q. Please define power costs as the term is used in the context of this testimony and explain how they are calculated.

A. Power costs primarily represent the daily, variable financial expenses PacifiCorp incurs to physically generate and deliver electricity to its customers. These costs do not include fixed capital expenses, such as the cost to build a power plant or the salaries of our employees. Furthermore, PacifiCorp only recovers these direct costs; PacifiCorp does not earn a return on these costs. In the context of this testimony, power costs are calculated with three additions and two revenue credits. The three additions are as follows:

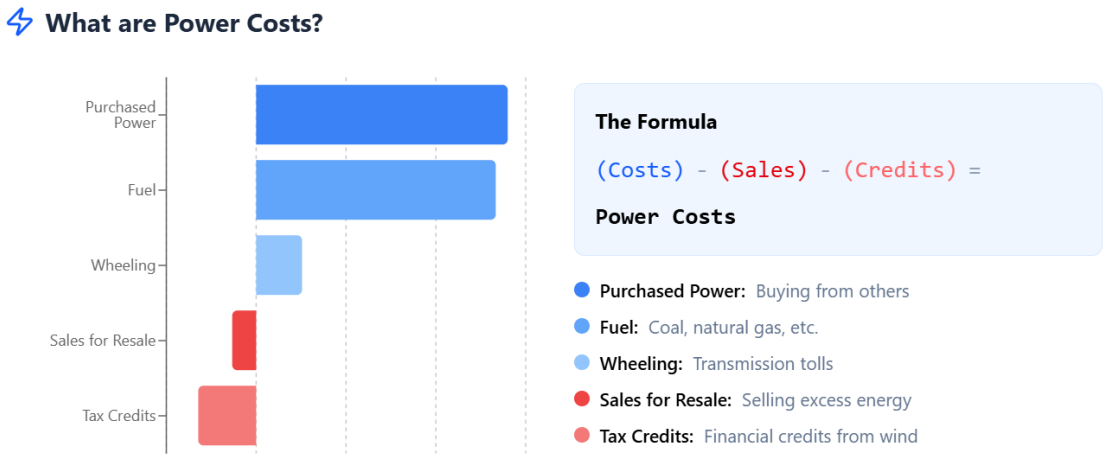
1. First, we add the cost of the consumable fuel, such as natural gas or coal, required to run PacifiCorp's thermal power plants.
2. Second, we add the cost of purchasing supplemental electricity—as and when economical—from the wholesale markets.
3. Third, we add the wheeling fees PacifiCorp must pay to other transmission owners to transport electricity across their transmission lines.

The two revenue credits are as follows:

1. First, we credit the revenue PacifiCorp earns when the system produces excess electricity that is sold into the wholesale market. The revenue from these sales acts as a financial credit that reduces overall power costs.
2. Second, we credit the revenue generated when PacifiCorp's wind facilities earn production tax credits. This revenue also acts as a financial credit that reduces overall power costs.

Figure 1 below illustrates the components of power costs and the revenue credits that offset them.

Figure 1



Q. How do you measure the impact of power costs on customers?

A. To objectively evaluate the power costs impact of the Service Area Transfer on customers, we measure the unit cost of power. The unit cost of power isolates the average power cost to produce exactly one standard unit of electricity for customers, which is mathematically expressed as dollars per megawatt-hour ("$/MWh"). Therefore, when speaking of the unit cost of electricity, the concept being discussed is the unit cost of power costs ("unit cost of power").

Q. Why is the unit cost of power a more appropriate metric for evaluating customer impacts than total dollars?

A. Evaluating total dollars alone presents an incomplete picture when assessing the impact on a customer. If a utility divests a large segment of its customer base, its total power costs will inherently decrease because the aggregate volume of fuel and purchased power required to serve the remaining system is substantially smaller. However, if the utility concurrently loses economic power plants, power costs to generate power for the

remaining customers could increase. The $/MWh metric isolates the average power cost to produce exactly one standard unit of electricity for customers, thereby controlling for changes in system size. Therefore, objectively evaluating the Service Area Transfer requires prioritizing the $/MWh metric over these offsetting changes in total dollar amounts.

Q. What is the difference between a megawatt and an average megawatt?

A. A megawatt is a standard measure of instantaneous electrical power capacity. It describes the maximum output a power plant can produce, or the maximum demand customers can draw, at a single moment in time. Conversely, an average megawatt is a mathematical metric used to express continuous energy production or consumption over a period of time. Specifically, one average megawatt denotes exactly one megawatt of power supplied continuously, 24 hours a day, 365 days a year. Using average megawatts allows us to compare highly fluctuating variables on a standardized basis.

IV. REDUCTIONS IN THE UNIT COST OF POWER

Q. What specific physical assets and customer obligations are included in the Service Area Transfer?

A. On an annualized average basis, under forward-looking system normal conditions,[2] the transaction permanently removes 515 average megawatts of retail customer load from our system. Concurrently, the transaction removes 314 average megawatts of physical power supply. This generation supply includes 104 average megawatts of wind generation from the Goodnoe Hills and Marengo wind facilities, 209 average

[2] Post-2030, post-Service Area Transfer transitional agreements, post-sale rate credits.

megawatts of natural gas generation from the Chehalis plant, and 1 average megawatt of generation from specific legacy qualifying facility power purchase agreements. The critical structural fact is that the load removed (515 average megawatts) exceeds the generation removed (314 average megawatts) by 201 average megawatts. This surplus is the primary driver of the power costs benefits I describe below.

Q. How does removing both customer load and generation facilities simultaneously affect the unit cost of power?

A. It results in a decrease to the system average unit cost of power by 23 cents per megawatt-hour in aggregate during the 2030 Forward Period,[3] a 0.61 percent reduction. On a Utah-allocated basis, this equates to approximately $7.2 million in annualized aggregate power costs savings, as shown on the 'Summary' pages within Confidential Exhibits RMP___(RJM-1) and RMP___(RJM-2).[4] This result is driven by favorable avoided cost differentials: the financial burden we avoid by no longer serving the Washington load exceeds the market cost required to replace the transferred generation, which fundamentally optimizes the system's load-resource balance for the remaining customers.

[3] Under forward-looking system normal conditions. The 2030 Forward Period employs a counterfactual assumption whereby transitional agreements with PGE end on December 31, 2029. This allows us to evaluate a full 12-month post-transition snapshot.

[4] The Utah-specific unit cost decrease of $0.23 per megawatt-hour and the $7.2 million in annualized savings reflect the application of Utah allocation factors under the 2020 Inter-Jurisdictional Cost Allocation Protocol to total-company adjusted net power costs results. In calendar year 2027, the savings are $2.7 million. For the 2030 Forward Period, the 5-state system power costs decrease by $16.6 million in total, and for calendar year 2027, the 5-state system power costs decrease by $5.4 million in total.

Q. Please explain the mathematics behind this avoided cost concept.

A. We compare the financial savings of no longer serving the Washington customer load against the financial cost of replacing the lost generation under forward-looking system normal conditions.

First, we calculate the savings from removing the load. The system avoids serving 515 average megawatts of Washington load. PacifiCorp avoids purchasing that power at the system marginal cost, represented by the wholesale market price of approximately $64 per megawatt-hour. This results in a gross savings of $32,960 per hour.[5]

Second, we calculate the cost of losing the generation. The system loses 314 average megawatts of energy. This total consists of 104 average megawatts of wind at a renewable energy credit of approximately $6 per megawatt-hour,[6] 209 average megawatts of natural gas energy at a fuel cost of approximately $47 per megawatt-hour, and one average megawatt of contract energy at a contract cost of approximately $87 per megawatt-hour. Replacing these 314 average megawatts of energy by purchasing it from the wholesale market at an approximate price of $64 per megawatt-hour costs $20,096 per hour.[7] However, because we no longer operate those transferred plants, we avoid their total fuel, production tax credit, and contract costs of approximately $9,286 per hour.[8] Therefore, the net cost to purchase replacement power is approximately $10,810 per hour.[9]

[5] 515 average megawatts ("aMW") * $64/MWh = $32,960.
[6] Under forward-looking system normal conditions, production tax credits on Marengo and Goodnoe Hills expire.
[7] 314 aMW * $64/MWh = $20,096.
[8] 104 aMW * (-)$6/MWh + 209 aMW * $47/MWh + 1 aMW * $87/MWh = $9,286.
[9] $20,096 - $9,286 = $10,810.

Q. What is the result of comparing those costs and savings?

A. We subtract the net replacement power cost of $10,810 per hour from the gross avoided load savings of $32,960 per hour. This calculation yields net savings of approximately $22,150 per hour.

If we divide that net savings of $22,150 per hour by the 515 average megawatts of total load removed, we find that the effective cost rate of the removed slice of the system is approximately $43.1 per megawatt-hour. The pre-sale average unit cost of power for our entire system is approximately $38.4 per megawatt-hour. Because we are removing a portion of the system whose effective cost ($43.1/MWh) exceeds the system average ($38.4/MWh), the remaining system's average unit cost mathematically decreases, which results in direct cost savings for remaining customers.

Q. This average megawatt analysis appears simplified. How do you validate the results?

A. The illustrative analysis above relies on averages to clearly explain the fundamental economic mechanics of the transaction. However, actual power operations are highly dynamic. Therefore, to further evaluate impacts on customers, we employed power costs modeling, whose results are presented on the 'Delta Model Forecast' page within Confidential Exhibit RMP___(RJM-3).

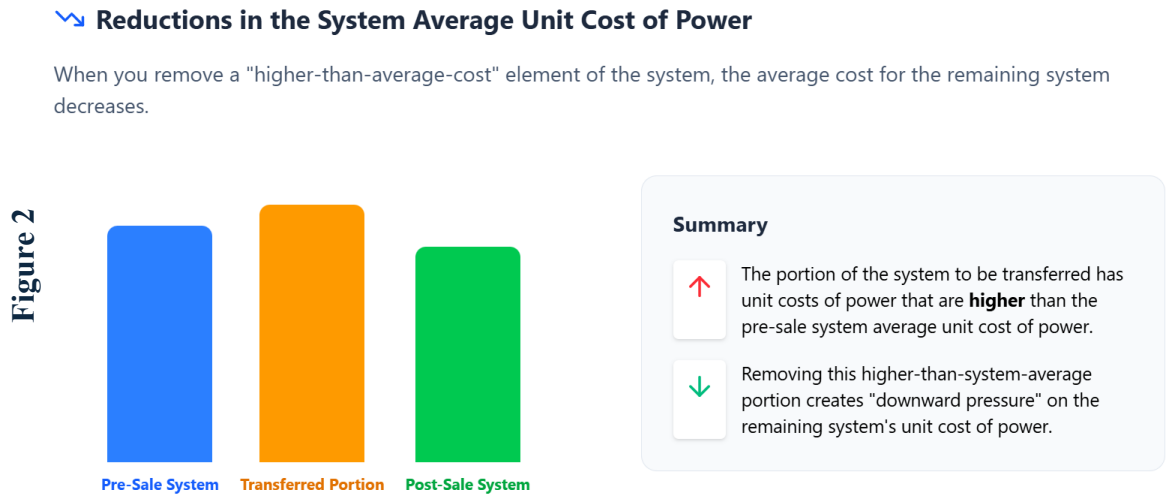
This modeling confirms and extends the directional analysis. As a further cross-check, PacifiCorp also performed an independent average-megawatt-based analysis that confirms the annual direction and magnitude of the unit cost decrease. Specifically, the production cost modeling provides unit cost of power changes for each month of the 2030 Forward Period, computed under that month's unique combination of load,

generation, and wholesale market prices. Because market conditions differ substantially across each of the 12 months, the dataset represents a diverse spectrum of operating conditions. During these periods, forecasted wholesale prices range from approximately $54 per megawatt-hour up to $105 per megawatt-hour.

Q. Your analysis demonstrates favorable energy impacts for customers. Are there also favorable impacts from changes in system capacity?

A. My testimony deals with energy and its associated power costs impacts. PacifiCorp witness Michael G. Wilding speaks to resource adequacy and details how customers in the remaining five states are favorably impacted by the system's capacity changes.

Figure 2



V. HISTORICAL VALIDATION OF STRUCTURAL BENEFITS

Q. To provide additional assurance beyond production cost modeling, you also performed a historical validation. Can you describe that analysis and confirm whether the structural benefit holds under actual observed conditions?

A. Yes. To corroborate the forward-looking results, we applied the same analytical framework to 48 months of actual, observed system conditions and wholesale market prices from January 2022 through December 2025 (the "Historical Period"). This

Historical Validation analysis uses PacifiCorp's actual load, actual wind generation from Goodnoe Hills and Marengo, actual Chehalis dispatch and fuel costs, actual qualifying facility output, and actual wholesale market prices for each month. No forecasted inputs were used. The methodology is identical to the forward-looking analysis discussed above: for each historical month, we calculate what the unit cost of power would have been had the Service Area Transfer been in effect, and compare it to the actual unit cost of power for that month. The detailed monthly results are presented on the 'aMW Delta Analysis Historical' page within Confidential Exhibit RMP___(RJM-3).

Q. What do the historical results show?

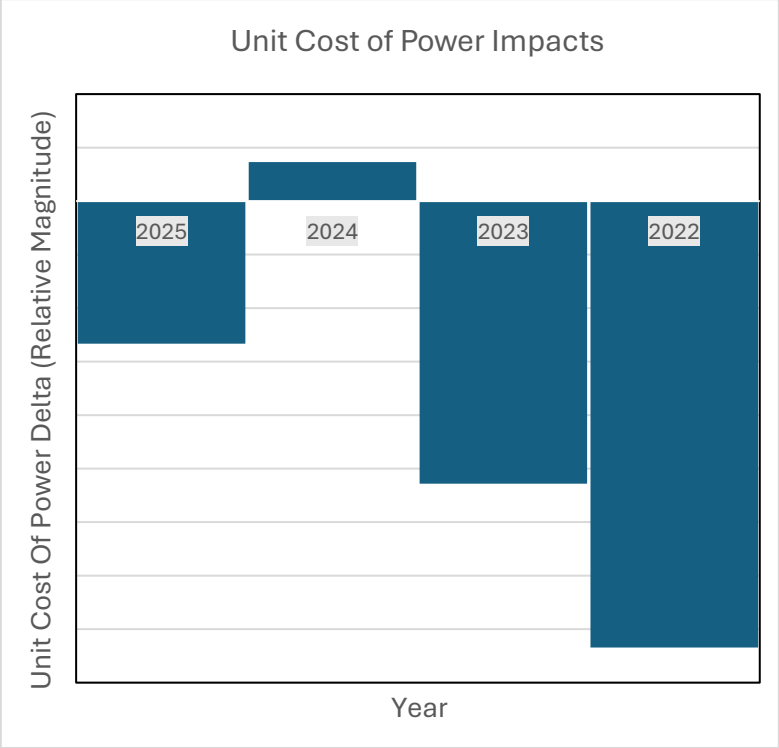
A. On an aggregate basis across the 48 months, the unit cost of power decreases. Across the 48 months, 71 percent of the months show a decrease in the unit cost of power and 29 percent of the months show an increase in unit cost of power. On a dollar-weighted basis, 96 percent of the total change reflects decreases in the unit cost of power, and 4 percent reflects increases. This is illustrated in Figure 3 below.

On an aggregate annual basis, the unit cost of power decreases in three of the four calendar years examined.[10] Critically, the historical period encompasses actual observed wholesale market prices ranging from $36 per megawatt-hour to $248 per megawatt-hour—a range more than four times as wide as the $54 to $105 per megawatt-hour range reflected in the forward-looking analyses. The structural benefit persists through the December 2022 price spike at $248 per megawatt-hour and the January 2024 winter event at $208 per megawatt-hour. Because the historical analysis

[10] Calendar year 2024 is the year with an increase in the unit cost of power.

uses actual data rather than forecasted inputs, it is immune to the critique that forecasted market prices, load shapes, or generation profiles may not materialize.

Figure 3



Q. How does the 2024 historical data further validate the robustness of the structural benefit?

A. Calendar year 2024 is the sole year with an aggregate unit cost increase, yet it validates the structural nature of the benefit even under extreme historical market conditions. The 2024 result is driven by three consecutive months—July, August, and September 2024—during which wholesale market prices sustained extreme levels between $130 and $159 per megawatt-hour. During those specific conditions, Chehalis was dispatched at very high capacity factors, causing the generation removed by the transaction to approach parity with the load removed. When the generation-to-load ratio approaches one-to-one, the favorable imbalance that structurally drives the unit cost of power decreases is diminished.

Critically, however, even in this worst-case historical year, the aggregate annual unit cost increase was a relatively de minimis 15 cents per megawatt-hour. This increase was overwhelmed by the decreases in the other three calendar years: $1.67 per megawatt-hour in 2022, $1.06 per megawatt-hour in 2023, and $0.53 per megawatt-hour in 2025. Over the full four-year historical period, the average annual net unit cost decrease is approximately $0.76 per megawatt-hour, demonstrating that even accounting for the unfavorable 2024 result, the long-run structural benefit is valid. Moreover, these outlier 2024 summer conditions exceed the worst-case market prices reflected in the 2030 Forward Period's forward-looking analysis.

Q. Elaborate on how there is a structural benefit to customers that persists under a diverse spectrum of system conditions despite some months within the 2030 Forward Period and the Historical Period showing unit cost increases.

A. Because each month reflects a unique combination of seasonal load patterns, weather-dependent generation, and prevailing wholesale market prices, some individual months show a higher post-sale unit cost than the pre-sale unit cost.

Operationally, these increases occur primarily in some "shoulder" months (such as May) when low wholesale market prices reduce the financial benefit of avoiding Washington load service, or during some summer months (such as July) when Chehalis is dispatched at very high capacity factors, causing the generation removed by the transaction to approach parity with the load removed.

However, during winter peaks (such as December and January) wholesale market prices or natural gas fuel prices are high. During these critical months, avoiding

over 515 average megawatts of load service yields financial savings that dwarf the aforementioned increases in some shoulder or summer months.

Net power costs and associated rate recovery mechanisms are generally evaluated on an annual basis specifically to absorb and smooth these seasonal variances.

VI. RENEWABLE ENERGY CREDITS

Q. Is there another driver of power costs that decreases customer rates in 2030?

A. Yes. Currently, PacifiCorp must satisfy the requirements of Washington's Clean Energy Transformation Act, which requires at least 80 percent of electric utilities' electricity supply to be generated from renewable or non-emitting resources by 2030. In the 2030 Forward Period PacifiCorp will avoid the need to procure renewable energy credits equivalent to 80 percent of Washington's retail load. On the other hand, PacifiCorp will also no longer own the Marengo and Goodnoe Hills wind facilities. However, the amount of renewable energy credits needed to comply with the Clean Energy Transformation Act is greater than the amount of renewable energy credits lost from those wind facilities. The valuation of that net increase in available renewable energy credits is approximately $2.4 million,[11] as detailed on the 'State Summary' page within Confidential Exhibit RMP___(RJM-4). This further decreases the unit cost of power.

[11] $0.15 million in 2027. For the 2030 Forward Period, the 5-state system's value of the net increase in renewable energy credits is a total of $4.9 million, and for calendar year 2027, the 5-state system's value of the net increase in renewable energy credits is a total of $0.32 million.

VII. CURING A STRUCTURAL MISALIGNMENT

Q. How does the sale of the Chehalis natural gas plant affect the economic cost of the system?

A. Currently, the Chehalis plant incurs annual costs under Washington's Climate Commitment Act, a cap-and-invest program that requires regulated entities to obtain allowances for greenhouse gas emissions. These costs have been disallowed for recovery through customer rates by the Commission.[12] However, these are actual costs incurred by PacifiCorp to operate the Chehalis plant as part of its integrated system. The Service Area Transfer eliminates this ongoing inter-jurisdictional cost allocation challenge.

Q. How does the Service Area Transfer impact this dynamic?

A. By transferring the Chehalis plant to Gem, PacifiCorp permanently eliminates its exposure to the Climate Commitment Act compliance costs and removes the associated regulatory uncertainty from the remaining system. This benefits remaining customers by eliminating the risk that future proceedings could revisit the allocation of these costs. From a power costs perspective, when conducting the pre-sale analysis inclusive of Climate Commitment Act costs for operating Chehalis, the system average unit cost of power decreases even further upon the Service Area Transfer, because PacifiCorp will no longer incur those compliance costs. Under this context, the unit cost of power in the 2030 Forward Period reduces even further.

[12] *Rocky Mountain Power's Application for Approval of the 2024 Energy Balancing Account*, Docket No. 24-035-01, Order at 25 (Feb. 25, 2025); *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket Nos. 24-035-04 *et al.*, Order at 48 (Apr. 25, 2025).

VIII. CONCLUSION

Q. In summary, what does your analysis demonstrate regarding the impact of the Service Area Transfer on power costs?

A. The evidence in this record demonstrates, on a quantified, month-by-month basis across the 2030 Forward Period and across 48 months of actual historical system conditions, that the Service Area Transfer reduces the average unit cost of power for PacifiCorp's remaining customers. Specifically:

1. The unit cost of power decreases by $0.23/MWh in the 2030 Forward Period, equating to approximately $7.2 million in annualized, ongoing power cost savings after the transitional agreements expire.
2. Historical validation using 48 months of actual system conditions from January 2022 through December 2025 independently confirms the structural benefit: the annual unit cost of power decreases in three of four calendar years, with 96 percent of the amount of the unit cost of power change being a decrease across those 48 months.
3. The net increase in available renewable energy credits resulting from the Service Area Transfer is approximately $2.4 million.
4. The transaction cures a structural misalignment related to Washington's Climate Commitment Act, eliminating regulatory uncertainty.
5. This analysis is robust across wholesale market prices ranging from $54/MWh to $105/MWh in the 2030 Forward Period and from $36/MWh to $248/MWh in the historical analyses, demonstrating that the benefit is structural rather than dependent on any single market assumption.

For all of these reasons, the Service Area Transfer provides comprehensive and quantifiable power costs benefits for PacifiCorp's remaining customers.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RJM-1)
Docket No. 26-035-20
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Power Costs Allocation Pre Sale 2030 Forward

April 2026

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER AND IN EXCEL FORMAT ONLY

REDACTED
Rocky Mountain Power
Exhibit RMP___(RJM-2)
Docket No. 26-035-20
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Power Costs Allocation Post Sale 2030 Forward

April 2026

REDACTED

SUMMARY

State	Year	Power Costs Post-Sale ($)	Power Costs Pre- Sale ($)	Power Costs Delta ($)	[redacted]	Power Costs Delta ($/MWh)	Power Costs Delta (%)
CA	2030	$30,539,635	$30,989,612	($449,977)		($0.56)	(1.45%)
ID	2030	$144,766,714	$146,115,138	($1,348,423)		($0.34)	(0.92%)
OR	2030	$772,535,602	$777,761,364	($5,225,762)		($0.29)	(0.67%)
UT	2030	$1,185,483,724	$1,192,725,777	($7,242,053)		($0.23)	(0.61%)
WY	2030	$331,923,235	$334,215,722	($2,292,487)		($0.24)	(0.69%)

REDACTED
Rocky Mountain Power
Exhibit RMP___(RJM-3)
Docket No. 26-035-20
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Costs Report

April 2026

REDACTED

Delta Model Forecast

Date	Year	Power Costs Pre-Sale ($)	Power Costs Post-Sale ($)	Power Costs Delta ($)	[redacted]	Unit Cost Delta ($/MWh)	[redacted]
1/1/2027	2027	$151,166,788	$136,716,304	($14,450,485)		($0.67)	
2/1/2027	2027	$147,563,080	$134,766,780	($12,796,301)		($0.58)	
3/1/2027	2027	$151,870,970	$139,265,753	($12,605,217)		($0.60)	
4/1/2027	2027	$140,925,618	$140,127,318	($798,300)		$1.60	
5/1/2027	2027	$156,920,882	$149,897,357	($7,023,525)		$0.46	
6/1/2027	2027	$171,174,583	$164,656,607	($6,517,977)		$0.60	
7/1/2027	2027	$207,070,860	$194,406,940	($12,663,920)		$0.08	
8/1/2027	2027	$202,110,312	$185,263,654	($16,846,658)		($0.66)	
9/1/2027	2027	$186,660,442	$169,358,564	($17,301,878)		($1.01)	
10/1/2027	2027	$150,845,609	$144,540,877	($6,304,732)		$0.82	
11/1/2027	2027	$153,282,860	$143,081,647	($10,201,213)		$0.12	
12/1/2027	2027	$168,231,939	$146,526,302	($21,705,636)		($1.62)	
1/1/2030	2030 Forward	$205,991,100	$187,759,163	($18,231,937)		($0.59)	
2/1/2030	2030 Forward	$200,183,016	$184,153,450	($16,029,566)		($0.43)	
3/1/2030	2030 Forward	$204,890,824	$188,948,065	($15,942,759)		($0.50)	
4/1/2030	2030 Forward	$207,379,648	$201,033,876	($6,345,772)		$1.34	
5/1/2030	2030 Forward	$217,721,372	$205,278,985	($12,442,387)		$0.19	
6/1/2030	2030 Forward	$226,332,203	$209,932,588	($16,399,616)		($0.54)	
7/1/2030	2030 Forward	$281,464,647	$259,461,781	($22,002,866)		($0.74)	
8/1/2030	2030 Forward	$264,008,972	$238,394,277	($25,614,695)		($1.52)	
9/1/2030	2030 Forward	$238,458,659	$225,293,051	($13,165,608)		$0.34	
10/1/2030	2030 Forward	$200,301,643	$183,399,017	($16,902,626)		($0.72)	
11/1/2030	2030 Forward	$199,511,699	$181,438,600	($18,073,099)		($0.88)	
12/1/2030	2030 Forward	$202,483,846	$181,134,503	($21,349,343)		($1.14)	

Year	Power Costs Pre-Sale ($)	Power Costs Post-Sale ($)	[redacted]	Unit Cost Delta ($/MWh)	Unit Cost Delta (%)
2027	$1,987,823,945	$1,848,608,103		($0.14)	(0.48%)
2030 Forward	$2,648,727,630	$2,446,227,356		($0.46)	(1.19%)

REDACTED

aMW Delta Analysis Forecast

Date	Year	Hours	[redacted]	Avoided Load Cost ($)	Generation Market Value ($)	Avoided Generation Costs/Revenues	Net Replacement Power Cost ($)	Net System Savings ($)	Power Costs Pre-Sale ($)	Power Costs Post-Sale ($)	[redacted]	Unit Cost Delta ($/MWh)
1/1/2027	2027	744		($39,141,250)	$21,922,025	($8,174,344)	$13,747,681	($25,393,569)	$151,166,788	$125,773,219		($2.68)
2/1/2027	2027	672		($23,664,525)	$12,702,548	($5,384,078)	$7,318,470	($16,346,055)	$147,563,080	$131,217,026		($1.32)
3/1/2027	2027	744		($16,501,436)	$15,151,530	($8,670,242)	$6,481,288	($10,020,148)	$151,870,970	$141,850,822		($0.08)
4/1/2027	2027	720		($12,716,823)	$13,880,693	($3,283,636)	$10,597,056	($2,119,767)	$140,925,618	$138,805,851		$1.32
5/1/2027	2027	744		($11,204,445)	$9,855,770	($1,937,496)	$7,918,273	($3,286,172)	$156,920,882	$153,634,710		$1.21
6/1/2027	2027	720		($13,623,735)	$9,564,499	($1,599,149)	$7,965,350	($5,658,385)	$171,174,583	$165,516,198		$0.76
7/1/2027	2027	744		($20,064,226)	$14,116,436	($3,790,698)	$10,325,737	($9,738,488)	$207,070,860	$197,332,372		$0.56
8/1/2027	2027	744		($23,027,985)	$13,531,915	($2,610,048)	$10,921,867	($12,106,118)	$202,110,312	$190,004,194		$0.14
9/1/2027	2027	720		($22,881,281)	$24,647,371	($6,199,700)	$18,447,671	($4,433,610)	$186,660,442	$182,226,832		$1.52
10/1/2027	2027	744		($24,653,095)	$23,870,636	($5,356,191)	$18,514,445	($6,138,650)	$150,845,609	$144,706,959		$0.85
11/1/2027	2027	720		($21,776,611)	$19,106,738	($10,325,674)	$8,781,063	($12,995,548)	$153,282,860	$140,287,312		($0.44)
12/1/2027	2027	744		($27,985,620)	$19,232,035	($12,891,857)	$6,340,177	($21,645,443)	$168,231,939	$146,586,496		($1.61)
1/1/2030	2030 Forward	744		($46,157,289)	$19,951,090	($7,591,894)	$12,359,195	($33,798,093)	$205,991,100	$172,193,006		($3.35)
2/1/2030	2030 Forward	672		($29,681,928)	$19,042,231	($8,116,514)	$10,925,717	($18,756,211)	$200,183,016	$181,426,806		($0.98)
3/1/2030	2030 Forward	744		($19,810,395)	$11,057,447	($5,145,764)	$5,911,683	($13,898,712)	$204,890,824	$190,992,112		($0.10)
4/1/2030	2030 Forward	720		($13,021,892)	$7,348,041	($4,070,862)	$3,277,179	($9,744,713)	$207,379,648	$197,634,934		$0.64
5/1/2030	2030 Forward	744		($9,157,888)	$5,308,742	($4,314,857)	$993,885	($8,164,002)	$217,721,372	$209,557,370		$1.03
6/1/2030	2030 Forward	720		($18,535,043)	$9,688,287	($4,036,062)	$5,652,226	($12,882,818)	$226,332,203	$213,449,386		$0.11
7/1/2030	2030 Forward	744		($29,559,594)	$21,870,981	($8,528,890)	$13,342,091	($16,217,503)	$281,464,647	$265,247,144		$0.18
8/1/2030	2030 Forward	744		($29,103,515)	$16,476,098	($6,242,943)	$10,233,155	($18,870,359)	$264,008,972	$245,138,613		($0.40)
9/1/2030	2030 Forward	720		($26,735,408)	$25,395,380	($10,644,946)	$14,750,434	($11,984,974)	$238,458,659	$226,473,685		$0.57
10/1/2030	2030 Forward	744		($23,048,010)	$15,628,610	($7,219,342)	$8,409,268	($14,638,742)	$200,301,643	$185,662,901		($0.27)
11/1/2030	2030 Forward	720		($23,669,203)	$16,917,087	($9,014,202)	$7,902,885	($15,766,318)	$199,511,699	$183,745,381		($0.43)
12/1/2030	2030 Forward	744		($26,467,928)	$11,338,348	($6,958,405)	$4,379,944	($22,087,984)	$202,483,846	$180,395,862		($1.27)
2030 Forward	2030	8760		($288,933,317)	$176,097,702	($81,885,174)	$94,212,528	($194,720,789)	$2,648,727,630	$2,454,006,841		($0.34)
2030 Forward	2030	1		($32,960)	$20,096	($9,286)	$10,810	($22,150)	$302,366	$280,216		($0.32)

Year	Power Costs Pre-Sale ($)	Power Costs Post-Sale ($)	[redacted]	Unit Cost Delta ($/MWh)	Unit Cost Delta (%)
2027	$1,987,823,945	$1,857,941,992		$0.01	0.0%
2030 Forward	$2,648,727,630	$2,451,917,200		($0.37)	(1.0%)

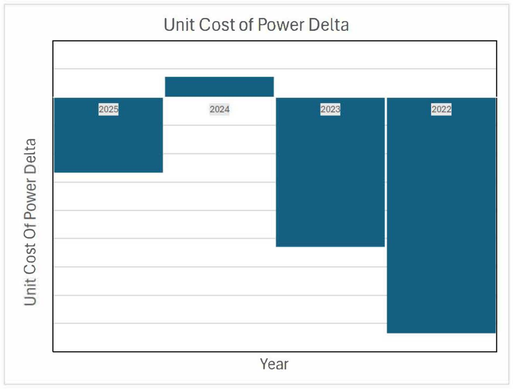
REDACTED

aMW Delta Analysis Historical

Date	Year	Hours	[redacted]	Avoided Load Cost ($)	Generation Market Value ($)	Avoided Generation Costs/Revenues	Net Replacement Power Cost ($)	Net System Savings ($)	Power Costs Pre-Sale ($)	Power Costs Post-Sale ($)	[redacted]	Unit Cost Delta ($/MWh)
12/1/2025	2025	744		($29,047,544)	$15,761,421	($9,033,950)	$6,727,470	($22,320,074)	$136,041,610	$113,721,536		($2.26)
11/1/2025	2025	720		($29,226,044)	$16,446,130	($11,067,985)	$5,378,146	($23,847,899)	$149,559,816	$125,711,918		($2.76)
10/1/2025	2025	744		($27,606,783)	$25,362,518	($7,638,149)	$17,724,369	($9,882,413)	$150,153,087	$140,270,674		$0.20
9/1/2025	2025	720		($35,730,016)	$29,455,895	($5,176,081)	$24,279,814	($11,450,202)	$196,204,795	$184,754,593		$0.18
8/1/2025	2025	744		($31,320,545)	$27,863,634	($5,099,662)	$22,763,971	($8,556,574)	$229,790,264	$221,233,690		$0.68
7/1/2025	2025	744		($31,327,072)	$26,682,891	($4,201,676)	$22,481,215	($8,845,858)	$241,506,087	$232,660,230		$0.70
6/1/2025	2025	720		($26,278,465)	$18,155,982	($2,450,181)	$15,705,800	($10,572,665)	$188,153,657	$177,580,992		$0.63
5/1/2025	2025	744		($22,578,189)	$15,470,109	($2,575,118)	$12,894,991	($9,683,198)	$155,991,690	$146,308,492		$0.58
4/1/2025	2025	720		($20,068,372)	$8,408,251	($1,511,951)	$6,896,300	($13,172,072)	$136,562,909	$123,390,836		($0.67)
3/1/2025	2025	744		($28,373,102)	$23,492,382	($10,914,211)	$12,578,171	($15,794,931)	$141,753,844	$125,958,913		($1.23)
2/1/2025	2025	672		($30,281,131)	$24,184,030	($12,075,001)	$12,109,029	($18,172,102)	$173,740,897	$155,568,796		($1.14)
1/1/2025	2025	744		($33,728,235)	$22,191,037	($14,263,188)	$7,927,849	($25,800,386)	$184,006,514	$158,206,128		($2.16)
12/1/2024	2024	744		($43,943,329)	$26,702,646	($13,492,880)	$13,209,766	($30,733,563)	$168,105,668	$137,372,105		($3.19)
11/1/2024	2024	720		($30,822,061)	$29,736,289	($13,265,008)	$16,471,281	($14,350,780)	$169,800,091	$155,449,311		($0.42)
10/1/2024	2024	744		($41,184,826)	$42,403,883	($5,584,969)	$36,818,913	($4,365,913)	$164,673,741	$160,307,828		$1.61
9/1/2024	2024	720		($48,859,343)	$43,998,595	($3,980,079)	$40,018,516	($8,840,828)	$248,578,673	$239,737,845		$1.27
8/1/2024	2024	744		($44,571,334)	$43,645,610	($5,025,482)	$38,620,129	($5,951,206)	$279,859,798	$273,908,592		$1.67
7/1/2024	2024	744		($43,867,766)	$45,408,574	($4,925,857)	$40,482,717	($3,385,048)	$314,852,101	$311,467,053		$2.37
6/1/2024	2024	720		($29,651,787)	$13,278,818	($1,850,229)	$11,428,589	($18,223,198)	$189,026,409	$170,803,211		($0.77)
5/1/2024	2024	744		($34,373,580)	$22,347,190	($1,562,432)	$20,784,757	($13,588,823)	$152,092,127	$138,503,304		($0.32)
4/1/2024	2024	720		($23,747,106)	$18,250,415	($2,001,357)	$16,249,058	($7,498,048)	$148,189,148	$140,691,100		$0.90
3/1/2024	2024	744		($20,734,535)	$18,511,525	($10,020,277)	$8,491,248	($12,243,287)	$158,163,741	$145,920,454		($0.32)
2/1/2024	2024	696		($28,624,121)	$23,208,863	($11,794,737)	$11,414,126	($17,209,995)	$181,281,611	$164,071,615		($0.80)
1/1/2024	2024	744		($88,905,184)	$73,416,397	($14,962,900)	$58,453,497	($30,451,687)	$318,001,079	$287,549,392		($1.20)
12/1/2023	2023	744		($32,490,022)	$14,036,548	($7,636,309)	$6,400,239	($26,089,783)	$180,596,682	$154,506,899		($2.25)
11/1/2023	2023	720		($35,416,193)	$17,326,558	($7,054,690)	$10,271,868	($25,144,325)	$181,132,068	$155,987,743		($2.45)
10/1/2023	2023	744		($46,861,472)	$39,473,765	($7,682,220)	$31,791,544	($15,069,928)	$167,396,187	$152,326,259		($0.43)
9/1/2023	2023	720		($53,955,404)	$49,479,572	($5,822,595)	$43,656,977	($10,298,427)	$224,866,312	$214,567,885		$0.95
8/1/2023	2023	744		($53,500,260)	$48,449,944	($5,777,193)	$42,672,750	($10,827,510)	$287,309,093	$276,481,583		$0.77
7/1/2023	2023	744		($48,855,763)	$28,376,663	($4,424,532)	$23,952,131	($24,903,632)	$288,981,994	$264,078,362		($1.66)
6/1/2023	2023	720		($30,069,579)	$11,414,715	($3,420,255)	$7,994,460	($22,075,119)	$171,185,695	$149,110,576		($1.93)
5/1/2023	2023	744		($23,213,098)	$12,129,941	($5,019,408)	$7,110,533	($16,102,564)	$152,061,048	$135,958,484		($0.99)
4/1/2023	2023	720		($28,634,758)	$20,647,624	($3,024,548)	$17,623,076	($11,011,682)	$147,599,301	$136,587,619		($0.25)
3/1/2023	2023	744		($34,529,565)	$42,750,262	($14,019,008)	$28,731,254	($5,798,311)	$196,426,040	$190,627,729		$1.35
2/1/2023	2023	672		($44,929,260)	$30,597,567	($15,176,081)	$15,421,486	($29,507,774)	$197,011,038	$167,503,264		($3.05)
1/1/2023	2023	744		($61,990,505)	$52,421,445	($20,843,202)	$31,578,242	($30,412,263)	$180,034,202	$149,621,938		($3.25)
12/1/2022	2022	744		($118,779,756)	$96,703,306	($37,725,130)	$58,978,176	($59,801,580)	$243,564,064	$183,762,484		($7.55)
11/1/2022	2022	720		($37,084,307)	$35,702,212	($19,218,925)	$16,483,287	($20,601,021)	$157,041,510	$136,440,489		($1.88)
10/1/2022	2022	744		($30,276,037)	$32,255,382	($13,621,958)	$18,633,424	($11,642,613)	$129,497,942	$117,855,329		($0.41)
9/1/2022	2022	720		($68,958,285)	$60,798,933	($9,504,075)	$51,294,858	($17,663,428)	$186,460,032	$168,796,605		($1.04)
8/1/2022	2022	744		($36,999,268)	$33,855,234	($9,518,001)	$24,337,233	($12,662,035)	$209,939,048	$197,277,013		($0.24)
7/1/2022	2022	744		($29,172,121)	$21,197,988	($6,711,159)	$14,486,828	($14,685,293)	$221,012,116	$206,326,824		($0.48)
6/1/2022	2022	720		($15,170,202)	$2,622,730	$1,391,989	$4,014,719	($11,155,483)	$124,640,439	$113,484,956		($0.08)
5/1/2022	2022	744		($31,405,057)	$7,407,138	$3,090,002	$10,497,141	($20,907,916)	$125,298,871	$104,390,955		($2.25)
4/1/2022	2022	720		($27,483,873)	$25,596,298	($7,891,944)	$17,704,355	($9,779,518)	$117,893,958	$108,114,440		($0.34)
3/1/2022	2022	744		($19,649,581)	$9,613,395	($1,100,295)	$8,513,100	($11,136,481)	$105,311,001	$94,174,520		($0.84)
2/1/2022	2022	672		($23,112,626)	$12,731,409	($3,845,309)	$8,886,099	($14,226,526)	$107,047,721	$92,821,195		($1.14)
1/1/2022	2022	744		($27,299,350)	$9,887,416	($12,945,223)	($3,057,807)	($30,357,157)	$127,472,375	$97,115,218		($3.77)

Year	Power Costs Pre-Sale ($)	Power Costs Post-Sale ($)	[redacted]	Unit Cost Delta ($/MWh)	Unit Cost Delta (%)
2025	$2,083,465,171	$1,905,366,798		($0.53)	(1.6%)
2024	$2,492,624,187	$2,325,781,811		$0.15	0.4%
2023	$2,374,599,659	$2,147,358,343		($1.06)	(2.8%)
2022	$1,855,179,079	$1,620,560,028		($1.67)	(5.6%)
Aggregate	$8,805,868,096	$7,999,066,980		**($0.76)**	**(2.2%)**

Direction	Value	Absolute Value	Ratio
Decrease	($3.26)	3.257578017	96%
Increase	$0.15	0.145993968	4%



REDACTED
Rocky Mountain Power
Exhibit RMP___(RJM-4)
Docket No. 26-035-20
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Renewable Energy Credits Report

April 2026

State Summary

Year	State	SG Allocation (%)
2030	CA	1.43%
2030	ID	6.53%
2030	OR	28.27%
2030	UT	48.77%
2030	WY	14.98%
2027	CA	1.43%
2027	ID	6.53%
2027	OR	28.27%
2027	UT	48.77%
2027	WY	14.98%

[redacted]

REDACTED
REC Benefit Summary