

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

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Direct Testimony of Ramon J. Mitchell

April 2026

1                                   **I.           INTRODUCTION AND QUALIFICATIONS**

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

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

7   **Q.    Please describe your education and professional experience.**

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

17   **Q.    Have you testified in previous regulatory proceedings?**

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

21 **II. PURPOSE OF TESTIMONY**

22 **Q. What is the overall purpose of your testimony?**

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

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

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

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<sup>1</sup> Post-2030, post-Service Area Transfer transitional agreements, post-sale rate credits.

41 **III. DEFINITION OF POWER COSTS**

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

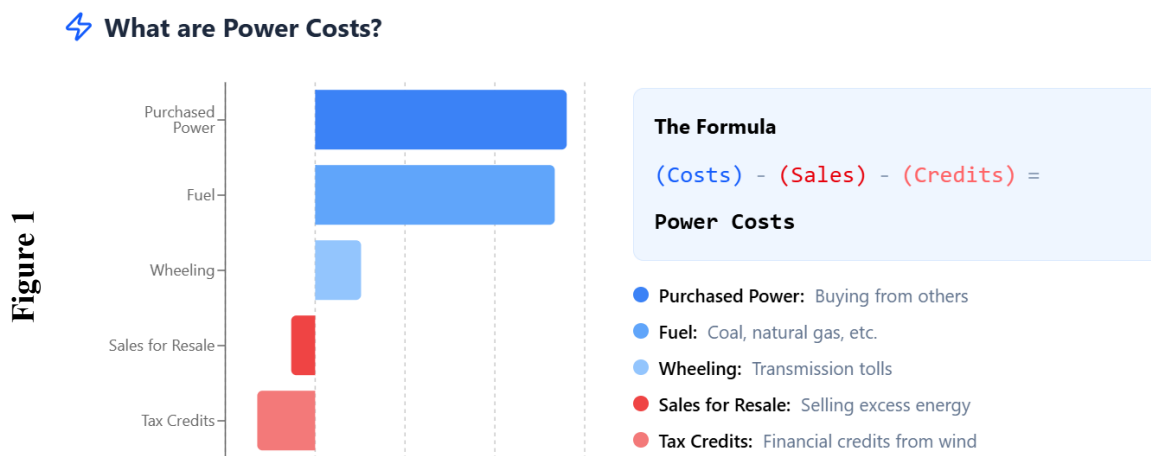
44 A. Power costs primarily represent the daily, variable financial expenses PacifiCorp incurs  
45 to physically generate and deliver electricity to its customers. These costs do not  
46 include fixed capital expenses, such as the cost to build a power plant or the salaries of  
47 our employees. Furthermore,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

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

57 The two revenue credits are as follows:

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

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



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

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

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

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

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

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

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

#### 94 **IV. REDUCTIONS IN THE UNIT COST OF POWER**

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

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

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<sup>2</sup> Post-2030, post-Service Area Transfer transitional agreements, post-sale rate credits.

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

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

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

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<sup>3</sup> 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.

<sup>4</sup> 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.

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

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

122 First, we calculate the savings from removing the load. The system avoids  
123 serving 515 average megawatts of Washington load. PacifiCorp avoids purchasing that  
124 power at the system marginal cost, represented by the wholesale market price of  
125 approximately \$64 per megawatt-hour. This results in a gross savings of \$32,960 per  
126 hour.<sup>5</sup>

127 Second, we calculate the cost of losing the generation. The system loses 314  
128 average megawatts of energy. This total consists of 104 average megawatts of wind at  
129 a renewable energy credit of approximately \$6 per megawatt-hour,<sup>6</sup> 209 average  
130 megawatts of natural gas energy at a fuel cost of approximately \$47 per megawatt-  
131 hour, and one average megawatt of contract energy at a contract cost of approximately  
132 \$87 per megawatt-hour. Replacing these 314 average megawatts of energy by  
133 purchasing it from the wholesale market at an approximate price of \$64 per megawatt-  
134 hour costs \$20,096 per hour.<sup>7</sup> However, because we no longer operate those transferred  
135 plants, we avoid their total fuel, production tax credit, and contract costs of  
136 approximately \$9,286 per hour.<sup>8</sup> Therefore, the net cost to purchase replacement power  
137 is approximately \$10,810 per hour.<sup>9</sup>

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<sup>5</sup> 515 average megawatts (“aMW”) \* \$64/MWh = \$32,960.

<sup>6</sup> Under forward-looking system normal conditions, production tax credits on Marengo and Goodnoe Hills expire.

<sup>7</sup> 314 aMW \* \$64/MWh = \$20,096.

<sup>8</sup> 104 aMW \* (-)\$6/MWh + 209 aMW \* \$47/MWh + 1 aMW \* \$87/MWh = \$9,286.

<sup>9</sup> \$20,096 - \$9,286 = \$10,810.

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

139 A. We subtract the net replacement power cost of \$10,810 per hour from the gross avoided  
140 load savings of \$32,960 per hour. This calculation yields net savings of approximately  
141 \$22,150 per hour.

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

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

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

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

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

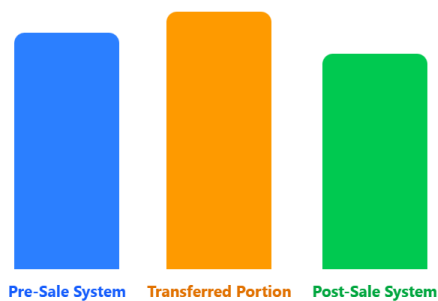
165 **Q. Your analysis demonstrates favorable energy impacts for customers. Are there**  
166 **also favorable impacts from changes in system capacity?**

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

#### ↘ Reductions in the System Average Unit Cost of Power

When you remove a "higher-than-average-cost" element of the system, the average cost for the remaining system decreases.

Figure 2



#### Summary

- ↑ The portion of the system to be transferred has unit costs of power that are **higher** than the pre-sale system average unit cost of power.
- ↓ Removing this higher-than-system-average portion creates "downward pressure" on the remaining system's unit cost of power.

## 170 V. HISTORICAL VALIDATION OF STRUCTURAL BENEFITS

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

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

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

186 **Q. What do the historical results show?**

187 A. On an aggregate basis across the 48 months, the unit cost of power decreases. Across  
188 the 48 months, 71 percent of the months show a decrease in the unit cost of power and  
189 29 percent of the months show an increase in unit cost of power. On a dollar-weighted  
190 basis, 96 percent of the total change reflects decreases in the unit cost of power, and 4  
191 percent reflects increases. This is illustrated in Figure 3 below.

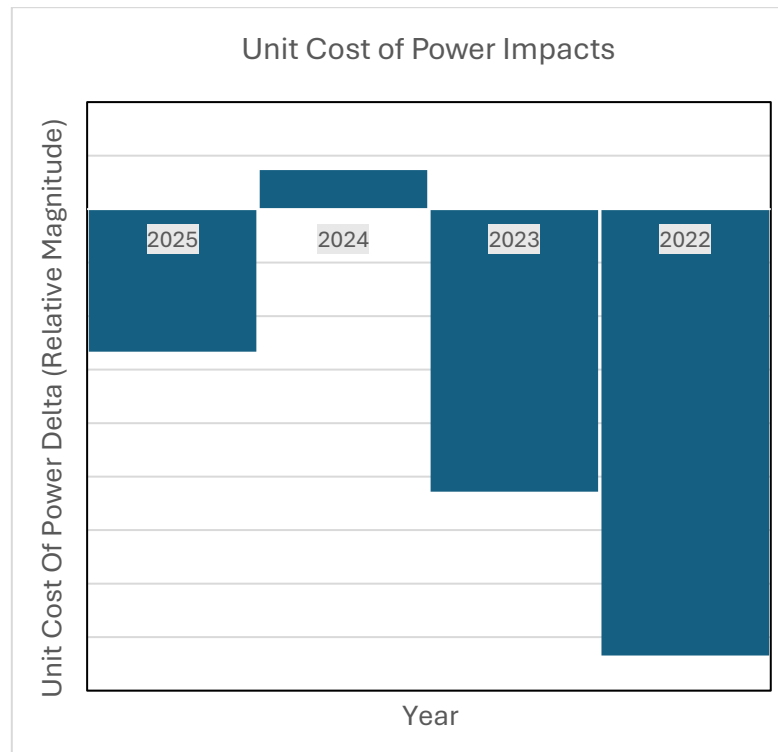
192 On an aggregate annual basis, the unit cost of power decreases in three of the  
193 four calendar years examined.<sup>10</sup> Critically, the historical period encompasses actual  
194 observed wholesale market prices ranging from \$36 per megawatt-hour to \$248 per  
195 megawatt-hour—a range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

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<sup>10</sup> Calendar year 2024 is the year with an increase in the unit cost of power.

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

Figure 3



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

203 A. Calendar year 2024 is the sole year with an aggregate unit cost increase, yet it validates  
204 the structural nature of the benefit even under extreme historical market conditions.  
205 The 2024 result is driven by three consecutive months—July, August, and September  
206 2024—during which wholesale market prices sustained extreme levels between \$130  
207 and \$159 per megawatt-hour. During those specific conditions, Chehalis was  
208 dispatched at very high capacity factors, causing the generation removed by the  
209 transaction to approach parity with the load removed. When the generation-to-load  
210 ratio approaches one-to-one, the favorable imbalance that structurally drives the unit  
211 cost of power decreases is diminished.

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

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

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

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

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

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

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

239 **VI. RENEWABLE ENERGY CREDITS**

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

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

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<sup>11</sup> \$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.

253 **VII. CURING A STRUCTURAL MISALIGNMENT**

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

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

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

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

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<sup>12</sup> *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).

273 **VIII. CONCLUSION**

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

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

- 280 1. The unit cost of power decreases by \$0.23/MWh in the 2030 Forward Period,  
281 equating to approximately \$7.2 million in annualized, ongoing power cost  
282 savings after the transitional agreements expire.
- 283 2. Historical validation using 48 months of actual system conditions from January  
284 2022 through December 2025 independently confirms the structural benefit: the  
285 annual unit cost of power decreases in three of four calendar years, with 96  
286 percent of the amount of the unit cost of power change being a decrease across  
287 those 48 months.
- 288 3. The net increase in available renewable energy credits resulting from the  
289 Service Area Transfer is approximately \$2.4 million.
- 290 4. The transaction cures a structural misalignment related to Washington's  
291 Climate Commitment Act, eliminating regulatory uncertainty.
- 292 5. This analysis is robust across wholesale market prices ranging from \$54/MWh  
293 to \$105/MWh in the 2030 Forward Period and from \$36/MWh to \$248/MWh  
294 in the historical analyses, demonstrating that the benefit is structural rather than  
295 dependent on any single market assumption.

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

298 **Q. Does this conclude your direct testimony?**

299 A. Yes.

**REDACTED**

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

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**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  
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**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 (\$) |  | 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)  
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**REDACTED**

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Costs Report

April 2026

| Date      | Year         | Power Costs Pre-Sale (\$) | Power Costs Post-Sale (\$) | Power Costs Delta (\$) | Unit Cost Delta (\$/MWh) |
|-----------|--------------|---------------------------|----------------------------|------------------------|--------------------------|
| 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 (\$) | 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%)             |

aMWDelta Analysis Forecast

| Date         | Year         | Hours | Generation Market Value (\$) | Avoided Generation Costs/Revenues | Net Replacement Power Cost (\$) | Net System Savings (\$) | Power Costs Pre-Sale (\$) | Power Costs Post-Sale (\$) | Unit Cost Delta (\$/MWh) |
|--------------|--------------|-------|------------------------------|-----------------------------------|---------------------------------|-------------------------|---------------------------|----------------------------|--------------------------|
| 1/1/2027     | 2027         | 744   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$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   | \$11,338,348                 | (\$6,958,405)                     | \$4,379,944                     | (\$22,087,984)          | \$202,483,846             | \$180,395,862              | (\$1.27)                 |
| 2030 Forward | 2030         | 8760  | \$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     | \$20,096                     | (\$9,286)                         | \$10,810                        | (\$22,150)              | \$302,366                 | \$280,216                  | (\$0.32)                 |

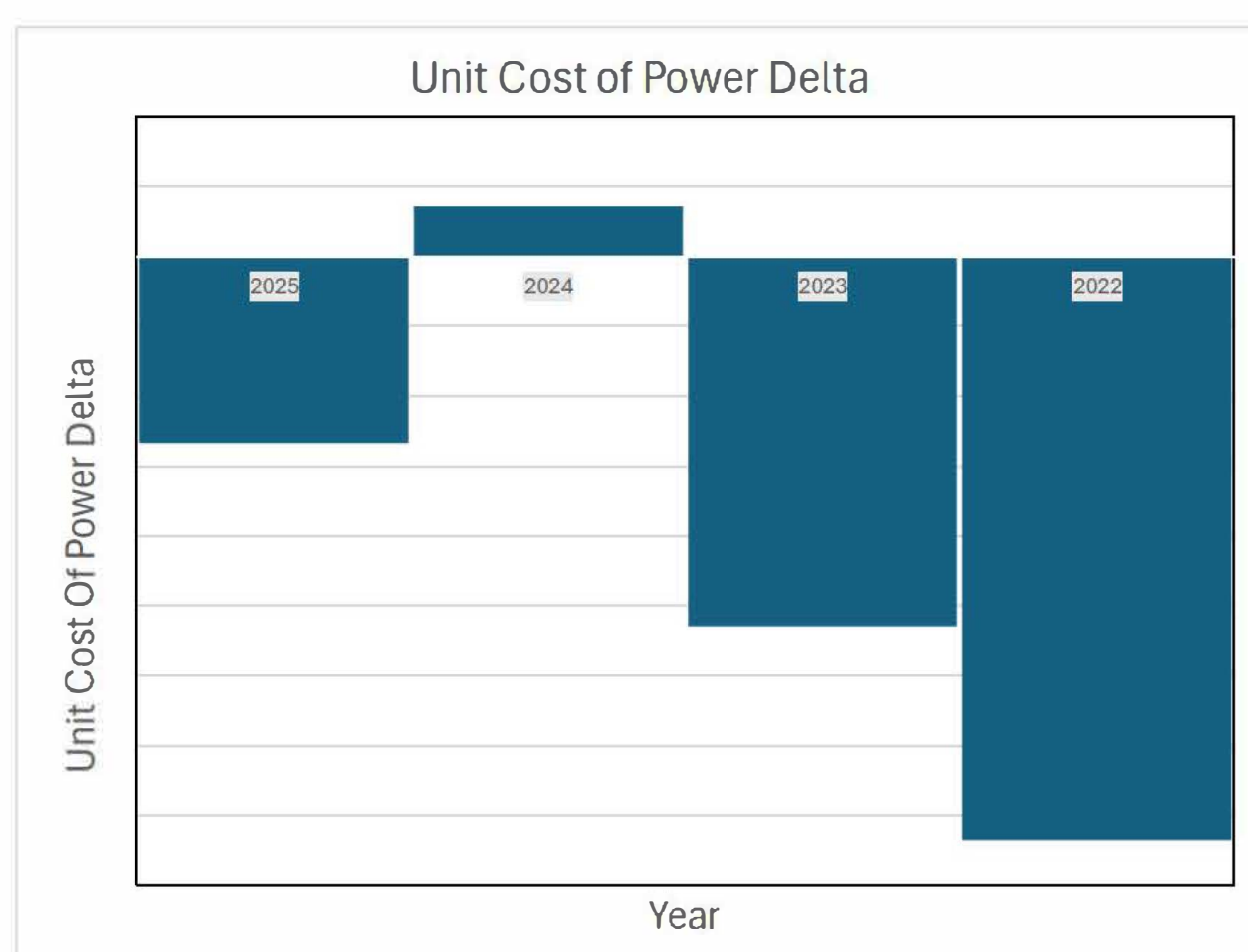
| Year         | Power Costs Pre-Sale (\$) | Power Costs Post-Sale (\$) | Unit Cost Delta (\$/MWh) | Unit Cost Delta (%) |
|--------------|---------------------------|----------------------------|--------------------------|---------------------|
| 2027         | \$1,987,823,945           | \$1,857,941,992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

aMW Delta Analysis Historical

| Date      | Year | Hours | 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 (\$) | 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   | (\$28,373,103)         | \$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                 | (\$9,516,001)                     | \$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 (\$) | 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

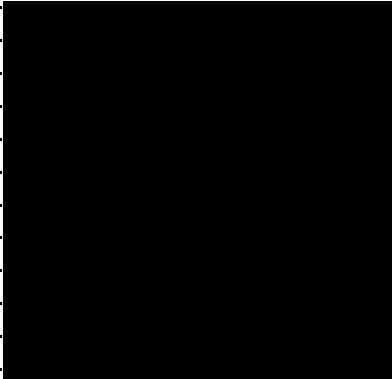
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**REDACTED**

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Renewable Energy Credits Report

April 2026

| 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%            |  |

