

Rocky Mountain Power
Docket No. 26-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Jack Painter

May 2026

1 **Q. Please state your name, business address, and present position with PacifiCorp**
2 **d/b/a Rocky Mountain Power (“Rocky Mountain Power” or the “Company”).**

3 A. My name is Jack Painter, and my business address is 825 NE Multnomah Street, Suite
4 600, Portland, Oregon 97232. My title is Net Power Cost Adviser.

5 **I. QUALIFICATIONS**

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

7 A. I received a Bachelor of Arts degree in Business Administration with a Finance major
8 from Washington State University in 2007. I have been employed by PacifiCorp since
9 2008 and have held positions in the regulation and jurisdictional loads departments. I
10 joined the regulatory net power costs group in 2019 and assumed my current role as a
11 Net Power Cost Adviser in 2024.

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

13 A. Yes. I have previously provided testimony to the public service commissions in Utah,
14 Idaho, Wyoming, Oregon, Washington, and California.

15 **II. PURPOSE OF TESTIMONY**

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

17 A. My testimony presents and supports the Company’s calculation of the
18 Energy Balancing Account (“EBA”) deferral for the 12-month period from
19 January 1, 2025, through December 31, 2025 (“Deferral Period”). More specifically, I
20 provide the following:

- 21 • Details supporting the calculation of the Company’s request to recover
22 \$190.6 million for excess EBA-related costs including interest, an adjustment
23 for sales made to a special contract customer, Utah situs-assigned resource

24 adjustments included in the EBA, an adjustment to reflect the Public Service
25 Commission of Utah’s (“Commission”) order in the 2025 EBA,¹ a reduction to
26 include the remaining over-collected balance from the 2024 EBA,² and an
27 adjustment to credit the EBA with 33 percent of Schedule 60 revenues from the
28 Electric Vehicle Infrastructure Program (“EVIP”);³ and

- 29 • Discussion of the main differences between adjusted actual net power costs
30 (“Actual NPC”) for calendar years 2025 and 2024 and net power costs in rates
31 (“Base NPC”).

32 **Q. Are any other witnesses presenting testimony specifically for the EBA and Electric**
33 **Service Schedule No. 94 (“Schedule 94”) in this case?**

34 A. Yes. Company witness Kenneth Lee Elder, Jr., Director, Pricing & Tariff Policy,
35 provides testimony on the proposed Schedule 94 rates.

36 III. SUMMARY OF THE EBA DEFERRAL CALCULATION

37 **Q. Please summarize the Company’s EBA application.**

38 A. The Company’s application requests recovery of \$190.6 million in deferred costs,
39 comprised of \$193.7 million of EBA-related costs, a credit of \$9.9 million for sales
40 made to a special contract customer, a \$7.9 million adjustment for Utah situs-assigned
41 resources, a credit of \$4.5 million to reflect the 2025 EBA Order, a \$13.0 million
42 reduction to reflect the remaining balance from the 2024 EBA, a credit of
43 approximately \$0.3 million for EVIP Schedule 60 revenue, and approximately \$16.7

¹ *Rocky Mountain Power’s Application for Approval of the 2025 Energy Balancing Account*, Docket No. 25-035-01, Order (Feb. 27, 2026) (“2025 EBA Order”).

² *Rocky Mountain Power’s Application for Approval of the 2023 Energy Balancing Account*, Docket No. 24-035-01, Order (Feb. 25, 2025) (“2024 EBA Order”).

³ *Rocky Mountain Power’s Application for Approval of Electrical Vehicle Infrastructure Program*, Docket No. 20-035-34, Order Approving Settlement Stipulation (Dec. 20, 2021) (“2021 EVIP Order”).

44 million of interest. The Company proposes to collect the deferred balance over 12
 45 months beginning July 1, 2026.

46 **Q. Are there any changes to the EBA deferral calculation?**

47 A. Yes. Changes have been included as part of the EBA calculation for base rates, which
 48 were updated in the 2024 General Rate Case (“2024 GRC”) and became effective
 49 April 25, 2025.⁴

50 **IV. EBA DEFERRAL CALCULATION**

51 **Q. Please describe the calculation of the EBA deferral included in this filing.**

52 A. Table 1 below provides a summary of the total EBA deferral and a breakdown of the
 53 individual components of the EBA. Additionally, Exhibit RMP____(JP-1) presents the
 54 detailed calculation of the EBA deferral on a monthly basis.

55 **Table 1**
 56 **Annual EBA Calculation**

Calendar Year 2025 EBA Deferral		<i>Exhibit RMP____(JP-1) Reference</i>
Actual EBA (\$/MWh)	\$ 28.98	<i>Line 6</i>
Base EBA (\$/MWh)	<u>21.78</u>	<i>Line 12</i>
\$/MWh Differential	\$ 7.20	
Utah Sales (MWh)	26,441,140	<i>Line 5</i>
EBA Deferrable*	\$ 193,655,162	<i>Line 14</i>
Special Contract Customer Adjustment*	(9,912,402)	<i>Line 17</i>
Utah Situs Resource Adjustment*	<u>7,867,402</u>	<i>Line 18</i>
Total Deferrable	\$ 191,610,162	<i>Line 19</i>
2024 EBA Collection True-Up	\$ (13,020,077)	<i>Line 24</i>
2025 EBA Final Order Settlement	(4,510,000)	<i>Line 25</i>
EVIP Revenue	(266,586)	<i>Line 23</i>
Interest Accrued through December 31, 2025	6,597,453	<i>Line 26</i>
Interest Accrued January 1, 2026 through March 31, 2026	2,446,524	<i>Line 28</i>
Interest Accrued April 1, 2026 through June 30, 2026	2,608,886	<i>Line 29</i>
Interest Accrued through Rate Effective Period July 1, 2026 through June 30, 2027	5,092,561	<i>Line 30</i>
Requested EBA Recovery	<u>\$ 190,558,923</u>	<i>Line 31</i>

* Calculated monthly

⁴ Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposal Electric Service Schedules and Electric Service Regulations, Docket No. 24-035-04, Order (April 25, 2025) (“2024 GRC Order”).

57 The EBA deferral of \$190.6 million is calculated as the difference between the
58 Actual NPC, Production Tax Credits (“PTCs”) and wheeling revenue and the Base
59 NPC, PTCs and wheeling revenue, as established in the 2020 general rate case (“2020
60 GRC”) and 2024 general rate case (“2024 GRC”).⁵ The calculation of the monthly
61 amount debited or credited into the EBA Deferral Account is based on the following
62 formula:

$$EBA\ Deferral_{Utah,month} = \left[\left(Actual\ EBAC_{\frac{Utah,month}{MWh}} - Base\ EBAC_{\frac{Utah,month}{MWh}} \right) \times Actual\ MWh_{Utah,month} \right]$$

63

64 **Q. What revenue requirement components are included in the EBA deferral**
65 **calculation?**

66 A. The EBA deferral calculation consists of three revenue requirement components: NPC,
67 PTCs and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale
68 purchase power expenses, and wheeling expenses, less wholesale sales revenue. PTCs
69 are credits the Company receives for generation at certain Company-owned wind
70 facilities that are included as an offset to the Company’s federal income taxes and
71 reduce net power costs for rate-making purposes. Wheeling revenue includes amounts
72 booked to Federal Energy Regulatory Commission (“FERC”) account 456.1 and
73 revenues from transmission of electricity of others. Collectively, these three
74 components are known in the Company’s EBA tariff, Schedule 94, as Energy Balancing
75 Account Costs (“EBAC”).

⁵ *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 No. 20-035-04, Order (Dec. 30, 2020) (“2020 GRC Order”); see also 2024 GRC Order.

76 **Q. How are the Utah-allocated Actual NPC calculated?**

77 A. Utah-allocated Actual NPC are calculated in three steps. First, unadjusted actual NPC
78 are established on a total-Company basis. Second, adjustments are made to the
79 unadjusted actual NPC to apply certain regulatory adjustments and to remove out-of-
80 period accounting entries. Third, the adjusted total-Company Actual NPC are allocated
81 to Utah based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.

82 **Q. What were the total-Company adjusted Actual NPC for the Deferral Period and**
83 **how were they determined?**

84 A. The total-Company adjusted Actual NPC in the Deferral Period were approximately
85 \$2.203 billion. This amount captures all components of NPC as defined in the
86 Company's GRC proceedings and modeled by the Company's power cost production
87 model. Specifically, it includes amounts booked to the following FERC accounts:

88 Account 447 – Sales for resale, excluding on-system wholesale sales and other
89 revenues that are not modeled in GRID

90 Account 501 – Fuel, steam generation; excluding fuel handling, start-up fuel
91 (gas and diesel fuel, residual disposal) and other costs that are
92 not modeled in GRID

93 Account 503 – Steam from other sources

94 Account 509 – Allowances

95 Account 547 – Fuel, other generation

96 Account 555 – Purchased power, excluding the Bonneville Power
97 Administration residential exchange credit pass-through if
98 applicable

99 Account 565 – Transmission of electricity by others

100 **Q. Does the Company have any updates to the potential FERC accounting change**
101 **that was noted in your testimony in the 2023 EBA proceeding?**

102 A. Yes. On June 29, 2023, the FERC issued Order No. 898 (Docket No. RM21-11-000),
103 Accounting and Reporting Treatment of Certain Renewable Energy Assets, to change
104 the accounting required for certain types of costs that have been previously booked to
105 FERC Account 555 to be booked to FERC account 509.⁶

106 **Q. Does FERC Order No. 898 impact the current EBA?**

107 A. Yes. The change from FERC account 555 to FERC account 509 for these costs becomes
108 effective January 1, 2025.

109 **Q. Did the Company update the accounts listed in Schedule 94 as recommended by**
110 **the Division of Public Utilities in the 2023 EBA?**

111 A. Mr. Elder presents the Company's revisions to Schedule 94 which includes an update
112 to the accounts listed for inclusion or exclusion from the EBA as recommended by
113 Division witness Gary Smith.

114 **Q. What adjustments are made to Actual NPC and why are they needed?**

115 A. The Company adjusts Actual NPC to reflect the ratemaking treatment of several items,
116 including:

- 117 • Out of period accounting entries booked in the Deferral Period that relate to
118 operations prior to implementation of the EBA in October 2011;
- 119 • Revenue from a contract related to the Leaning Juniper wind resource;
- 120 • Revenue for wheeling expense reimbursement from Orchard Wind QF;

⁶ *File Rule*, 183 FERC ¶ 61,205, Docket No. RM21-11-000 (Jun. 29, 2023) available at <https://www.ferc.gov/media/order-no-898>.

- 121 • Costs for situs-assigned resources/programs in Utah, Oregon, Washington,
122 California and Idaho;
- 123 • Situs assignment of Reasonable Energy Price adjustments to QF's;
- 124 • Coal inventory adjustments to reflect coal costs in the correct period; and
- 125 • Legal fees related to fines and citations included in the cost of coal.

126 Additional details regarding each of these adjustments and the impact on NPC are
127 provided in Additional Filing Requirement 15.

128 **Q. What allocation methodology did the Company use to calculate the EBA Deferral**
129 **Account balance?**

130 A. The 2020 GRC set the Base NPC effective January 1, 2021, in the 2020 GRC Order,
131 and the 2024 GRC set the Base NPC effective April 25, 2025, in the 2024 GRC Order,
132 using the Commission Order Method, which was originally approved by the
133 Commission in Docket No. 09-035-15. Exhibit RMP___(JP-1) calculates the EBA
134 deferral using the Commission Order Method for the entire Deferral Period.

135 **Q. Does the calculation of the EBA deferral include carrying charges?**

136 A. Yes. In accordance with the Commission's orders dated March 2, 2011, and
137 February 16, 2017, in Docket No. 09-035-15, carrying charges accrue on the monthly
138 EBA deferral. Effective January 1, 2020, the carrying charge is the customer deposit
139 rate for Residential and Non-residential Deposits in Electric Service Schedule No. 300.
140 Carrying charges accrue monthly during the Deferral Period, the review period, and
141 will continue to accumulate during the collection period. The estimated impact of
142 carrying charges during the rate effective period of July 1, 2026 through June 30, 2027
143 is included in the EBA calculation and the supporting calculation is provided in

144 Additional Filing Requirement 21.

145 **Q. Did the Commission approve inclusion of interest during the collection period?**

146 A. Yes. Carrying charges have always accrued during the collection period. Prior to the
147 2025 EBA, they were not included in the EBA filing and were instead recovered in a
148 subsequent EBA. In the 2025 EBA, the Company requested to include the collection
149 period carrying charges in the 2025 EBA amount requested at the time of application,
150 which was approved by the Commission.⁷

151 **Q. Please describe the impact of the special contract customer(s) in the EBA.**

152 A. A special contract customer pays rates specified in the contract and is not subject to
153 new EBA rates approved on or after December 1, 2016. The NPC associated with
154 serving the special contract customer are embedded in Actual NPC. As Utah tariff
155 customers benefit from the special contract remaining on the Company's system and
156 paying a portion of the total revenue requirement, the EBA deferral amount associated
157 with the special contract customer is shared among Utah tariff customers. Additionally,
158 a certain portion of the sales to a special contract customer are at a price different than
159 NPC in base rates, and an adjustment is made to the EBA in which the Utah tariff
160 customers share the variance between the contract price and Base NPC with the
161 Company.

162 **Q. Please describe the adjustment for sales made to a special contract customer.**

163 A. Per the stipulation in Docket No. 16-035-33, the EBA includes an adjustment for certain
164 sales made to the special contract customer.⁸ The adjustment calculates monthly the

⁷ 2025 EBA, Order Approving Interim Rates, (Jun. 30, 2025) at 6.

⁸ *In the Matter of Rocky Mountain Power for Approval of an Energy Service Contract with Kennecott Utah Copper, LLC*, Docket No. 16-035-33, Settlement Stipulation (Oct. 7, 2026) and Rocky Mountain Power's Addendum to the October 7, 2016 Settlement Stipulation (Aug. 7, 2016).

165 difference between the average monthly contract price paid and NPC in base rates
166 (“Special Contract Differential”). The Special Contract Differential is then multiplied
167 by the megawatt-hour (“MWh”) sales to the special contract customer to calculate the
168 dollar amount of the variance. The difference is then subject to a symmetrical deadband
169 of \$350,000. For the 2026 EBA, the adjustment for sales made to a special contract
170 customer is a \$9.9 million credit.

171 V. TREATMENT OF SITUS-ASSIGNED RESOURCES

172 **Q. What are situs-assigned resources?**

173 A. Situs-assigned resources are renewable resources that the Company acquired on behalf
174 of either individual states or customers in order to serve part or all of their energy needs.
175 Both the costs and benefits for these resources are situs-assigned to the state of origin.
176 Non-participating states should not bear higher costs for these resources.

177 **Q. Which resources or programs are considered situs-assigned?**

178 A. The Utah situs-assigned resources or programs are Pavant III Solar for the Utah
179 Subscriber Solar Program, Electric Service Schedule No. 136 Transition Program for
180 Customer Generators (“Schedule 136”), Electric Service Schedule No. 137 Net Billing
181 Service for Customer Generators (“Schedule 137”), Amor IX/Soda Lake Geothermal
182 and Castle Solar under Electric Service Schedule No. 32 (“Schedule 32”), and Cove
183 Mountain Solar 2, Graphite Solar, Appaloosa Solar 1A and 1B, Rocket Solar,
184 Horseshoe Solar, and Faraday Solar under Electric Service Schedule No. 34 (“Schedule
185 34”). Situs-assigned resources or programs in the Company’s remaining jurisdictions
186 are Black Cap Solar, Old Mill Solar, the Oregon Solar Incentive Plan, California
187 Electric Service Schedule No. 136 Net Billing, and Idaho Electric Service Schedule

188 No. 136 Net Billing.

189 **Q. How does the Company treat situs-assigned resources in the EBA?**

190 A. On a monthly basis, the Company uses either the actual cost or the mark-to-market
191 calculation for NPC allocation purposes, whichever is lower. This treatment will ensure
192 that non-participating states will not pay costs higher than actual costs and only the
193 costs that are above market will be situs-assigned to state of origin.

194 **Q. Are there any exceptions to the changes the Company has made?**

195 A. Yes. Black Cap Solar in Oregon is a Company leased resource that has continued the
196 sole use of the mark-to-market calculation because there is no Power Purchase
197 Agreement (“PPA”) costs in NPC. Additionally, because the Utah Subscriber Solar
198 Program and both Utah Schedule 32 and Schedule 34 resources, excluding Elektron
199 Solar, are paid entirely by the respective customers, the lower of actual cost or market
200 results in zero PPA costs.

201 **Q. Please describe the Utah Situs-Assigned Resource Adjustment.**

202 A. The Utah Situs-Assigned Resource Adjustment accounts for the Utah situs costs of
203 certain resources and expenses, namely the Utah Subscriber Solar Program, Schedule
204 136, Schedule 137, the Western Energy Imbalance Market (“WEIM”) Body of State
205 Regulators (“BOSR”) fees charged for commission related work as a participant in the
206 WEIM, and the Western Power Pool (“WPP”) Committee of State Representatives
207 (“COSR”) and Western Resource Adequacy Program (“WRAP”) implementation costs
208 and program coordination services.

209 **Q. Please describe the Utah Subscriber Solar Program.**

210 A. The Commission approved the “Subscriber Solar Program Rider - Optional” Electric

211 Service Schedule No. 73 (“Schedule 73”), effective March 21, 2016, which enables
212 participating Utah customers to purchase electricity from a specific utility-scale solar
213 resource.⁹ Customers can elect to purchase blocks of energy at a set amount each
214 month, and the value of any excess, unused block energy is rolled forward to future
215 months. Participating blocks of energy purchased are subject to rates specific to
216 Schedule 73 and are not subject to the EBA adjustment rate schedule changes (Schedule
217 73, Special Condition 15).

218 **Q. Please describe the situs-assigned adjustment to the EBA for the Utah Subscriber**
219 **Solar Program Resource.**

220 A. Under the stipulation in Docket No. 15-035-61, the solar resource is included as a Utah-
221 situs resource in net power costs.¹⁰ The generation costs of the solar resource are
222 compared to the generation charges paid by solar subscriber customers and the
223 difference is either recovered from or credited back to Utah customers through the
224 EBA. In addition, there are no load adjustments and no change in allocation factors due
225 to the program. The EBA adjustment for Subscriber Solar is a cost of \$0.2 million.

226 **Q. Please describe Schedule 136 Transition Program and Schedule 137 Net Billing**
227 **for Customer Generators.**

228 A. In Docket No. 14-035-114, the Commission approved Schedule 136, effective
229 November 14, 2017.¹¹ In Docket No. 17-035-61, the Commission approved Schedule

⁹ *In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73)*, Docket No. 15-035-61, Tariff Approval Letter from the Commission (March 21, 2016).

⁵ *In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73)*, Docket No. 15-035-61, Order Approving Amended Settlement Agreement, Exhibit A at 7 (Oct. 21, 2015).

¹¹ *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp’s Net Metering Program*, Docket No. 14-025-114, Order Approving Proposed Tariff Sheets and Allowing Additional Comment Period on Limited Issues (Nov. 14, 2017).

230 137, effective October 30, 2020.¹² Both programs enable eligible customers to offset
231 part or all of their own electrical requirements with self-generation and receive export
232 credits for energy fed back to the electric grid, which measures the difference between
233 the electricity supplied by the Company and the electricity generated by an eligible
234 customer-generator.

235 **Q. Please describe the situs-assigned adjustment to the EBA for the Schedule 136 and**
236 **Schedule 137 costs.**

237 A. The cost difference between export credits to eligible customers and the market value
238 of the exports is recovered from Utah customers through the EBA using the lower of
239 cost or market treatment described above. The EBA adjustment for Schedule 136 costs
240 is \$4.6 million and for Schedule 137 costs is \$2.9 million.

241 **Q. Please describe the situs-assigned adjustment to the EBA for the fees associated**
242 **with the WEIM BOSR, WPP COSR, and WPP WRAP.**

243 A. The WEIM BOSR fee supports the BOSR's expenses and supports the body's goal that
244 consistent and informed regulator engagement on regional market operations and
245 developments is crucial to efficient and sustainable markets that deliver public benefits.
246 The Utah allocated cost in the EBA is \$12,258. The WPP WRAP and its state
247 represented committee, COSR, is the regional resource adequacy initiative that is being
248 implemented by many utilities and power producers across the west to ensure that the
249 region is better able to plan for its regional resource adequacy needs. The Utah allocated
250 cost in the EBA is \$55,523 for the WRAP and \$11,195 for the COSR. The WEIM
251 BOSR and WPP WRAP fees were approved by the Commission for inclusion in the

¹² *Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity*, Docket No. 17-035-61, Order (Oct. 30, 2020).

252 EBA in Docket No. 22-035-01. The costs included in this EBA filing are for January 1,
253 2025 through April 24, 2025. Beginning April 25, 2025, these items are now included
254 in Base NPC rates as part of the 2024 GRC and will no longer be included in the EBA.

255 **Q. What is the WPP COSR?**

256 A. “The Committee of State Representatives (COSR) is a standing committee of the
257 Western Resource Adequacy Program (WRAP), a first-of-its-kind reliability program
258 in the West operated by the Western Power Pool (WPP). The WRAP tariff was approved
259 by the Federal Energy Regulatory Commission (FERC) at the beginning of 2023, and
260 the COSR was established soon after in April 2023 in accordance with the WRAP
261 Bylaws. The COSR aims to support state and provincial engagement in the WRAP and
262 share those valuable perspectives on pertinent program matters. The COSR will advise
263 the WPP Board of Directors, Program Review Committee (PRC), Resource Adequacy
264 Participants Committee (RAPC), any working groups or task forces, and the Federal
265 Energy Regulatory Commission (FERC) on matters related to WRAP governance,
266 program design, and operations. The COSR is composed of one representative from
267 each state or provincial jurisdiction that regulates at least one Participant. State and
268 provincial representatives are nominated by the Chair or President of their respective
269 public utility commissions and may include representatives from the state or provincial
270 energy offices or state or provincial funded consumer advocates. The COSR operates
271 in a public setting and welcomes other regional stakeholders to attend committee
272 meetings to better foster engagement and collaboration.”¹³

¹³ More information on the COSR is available at: <https://www.westernenergyboard.org/cosr/>.

273 **Q. Please describe the situs-assigned adjustment to the EBA for Schedule 32 and**
274 **Schedule 34 excess generation purchases.**

275 A. Schedule 32 and Schedule 34 are unique retail service options available to any customer
276 who would otherwise qualify for Electric Service Schedule Nos. 6, 8, or 9 that desires
277 to receive all or part of its electricity from a renewable energy facility. This allows the
278 Company to meet its customers' renewable energy goals while protecting the
279 Company's other customers from the financial impacts of another customer's
280 preference. Purchase power agreement costs and generation from renewable energy
281 facilities for the customer are removed from NPC in the EBA and any excess generation
282 is purchased at Electric Service Schedule No. 37 avoided costs rates. Total-Company
283 Schedule 32 and Schedule 34 excess generation costs in the EBA are \$11.5 million.

284 **Q. Please describe the new adjustment to include Schedule 60 revenues in the EBA**
285 **associated with the EVIP.**

286 A. The Company's EVIP was established through a Settlement Stipulation that was
287 approved by the Commission on December 29, 2021.¹⁴ The Settlement Stipulation
288 specified that thirty-three percent of the revenue collected from Company-owned
289 electric vehicle charging infrastructure through Schedule 60 would be credited to Utah
290 customers in the EBA.¹⁵ Therefore, \$266,586 is included in the EBA as a credit in
291 accordance with the terms of the Settlement Stipulation.

¹⁴ *Application of Rocky Mountain Power for Approval of Electrical Vehicle Infrastructure Program*, Docket No. 20-035-34, Order Approving Settlement Stipulation (Dec. 29, 2021).

¹⁵ *Application of Rocky Mountain Power for Approval of Electrical Vehicle Infrastructure Program* Docket No. 20-035-34, Settlement Stipulation at 8-9 (Nov. 6, 2021).

292 **Q. Please describe why there is a variance in the EVIP revenue credited in the EBA**
293 **and the EVIP revenue from Attachment A in the Company's EVIP report.**

294 A. The variance between the two is simply timing and is caused because the EVIP revenue
295 in Attachment A is accounted for on a cash basis while the EVIP revenue in the EBA is
296 accounted for an accrual basis.

297 **VI. DIFFERENCES IN NPC**

298 **Q. Please explain the Base NPC the Company used to calculate the NPC component**
299 **of the EBA deferral.**

300 A. The Base NPC for the 2025 EBA is comprised of two components. First the 2020 GRC
301 established Base NPC from January 1, 2021 through April 24, 2025 and set total-
302 Company Base NPC at \$23.61/MWh using a 12-month test period from January 2021
303 through December 2021. Second, the 2024 GRC updated Base NPC effective April 25,
304 2025 and set total-Company Base NPC at \$29.03/MWh using a 12-month test period
305 from January 2025 through December 2025. Based upon a normalized forecast with
306 perfect foresight, actual operating and market conditions will vary from Base NPC.

307 **Q. On a total-Company basis, what was the difference between Actual NPC and Base**
308 **NPC established in the 2024 GRC for the Deferral Period?**

309 A. On a total-Company basis, Actual NPC for the Deferral Period was \$34.30/MWh,
310 approximately \$5.27/MWh more than Base NPC established in the 2024 GRC for the
311 Deferral Period. Table 2 provides a high-level summary of the difference between Base
312 NPC established in the 2024 GRC and Actual NPC by category on a total-Company
313 basis.

314
315

Table 2
Net Power Cost Reconciliation (2025 Actual NPC and 2024 GRC Base NPC)

Net Power Costs \$/MWh	Actual	Base	Variance
Wholesale Sales	\$44.81	\$76.42	(\$31.61)
Purchased Power	\$51.31	\$62.26	(\$10.96)
Coal	\$30.35	\$31.80	(\$1.46)
Gas	\$34.38	\$42.29	(\$7.91)
Other	\$17.22	\$18.49	(\$1.28)
Total \$/MWh	\$34.30	\$29.03	\$5.27
Net Power Costs GWh			
Actual	Base	Variance	
Wholesale Sales	4,036	3,771	265
Purchased Power	18,743	23,335	(4,592)
Coal	23,289	21,519	1,770
Gas	15,375	14,688	687
Other	10,846	10,775	71
Total GWh	64,218	66,547	(2,329)
Net Power Costs \$			
Actual	Base	Variance	
Wholesale Sales	180,849,296	288,174,390	(107,325,094)
Purchased Power	961,619,745	1,452,895,054	(491,275,309)
Coal	706,769,032	684,383,693	22,385,340
Gas	528,571,922	621,172,172	(92,600,251)
Other	186,744,213	199,270,874	(12,526,661)
GRC Order Adjustments	-	(737,514,376)	737,514,376
Total \$	\$2,202,855,615	\$1,932,033,026	\$270,822,589

316 **Q. Please explain the primary differences in 2025 Actual NPC and Base NPC**
317 **established in the 2024 GRC.**

318 **A.** From an accounting perspective, and as shown in Table 2 above, Actual NPC differed
319 from Base NPC due to a \$107 million reduction in wholesale sales, a \$491 million
320 decrease in purchased power expense, a \$22 million increase in coal fuel expense, a
321 \$93 million increase in natural gas expense, and a \$13 million decrease in wheeling

322 and other expenses. Overall, the differences are due to lower market prices for
323 purchased power, lower natural gas prices and increased coal supply leading to
324 increased natural gas and coal generation volumes, and decreased load.

325 **Q. On a total-Company Utah-adjusted basis, what was the \$/MWh variance between**
326 **the current Deferral Period and calendar year 2024?**

327 A. From a \$/MWh perspective, Actual NPC for the Deferral Period was \$34.30/MWh
328 while calendar year 2024 Actual NPC was \$40.84/MWh, a decrease of \$6.54/MWh or
329 16.0 percent. Table 3 below displays Utah-adjusted Actual NPC for 2025 and 2024 with
330 a high-level summary of the differences, by cost category, on a total-company basis.

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Table 3
Net Power Cost Reconciliation (2025 Actual NPC and 2024 Actual NPC)

Net Power Costs \$/MWh	2025	2024	Variance
Wholesale Sales	\$44.81	\$54.35	(\$9.54)
Purchased Power	\$51.31	\$69.00	(\$17.69)
Coal	\$30.35	\$28.94	\$1.41
Gas	\$34.38	\$33.75	\$0.62
Other	\$17.22	\$18.75	(\$1.53)
Total \$/MWh	\$34.30	\$40.84	(\$6.54)
Net Power Costs GWh	2025	2024	Variance
Wholesale Sales	4,036	1,964	2,072
Purchased Power	18,743	20,595	(1,852)
Coal	23,289	18,225	5,064
Gas	15,375	16,942	(1,567)
Other	10,846	9,793	1,053
Total GWh	64,218	63,591	627
Net Power Costs \$	2025	2024	Variance
Wholesale Sales	180,849,296	106,724,822	74,124,474
Purchased Power	961,619,745	1,421,024,233	(459,404,489)
Coal	706,769,032	527,475,934	179,293,098
Gas	528,571,922	571,862,902	(43,290,980)
Other	186,744,213	183,618,646	3,125,566
Total \$	\$2,202,855,615	\$2,597,256,893	(\$394,401,278)

333 **Q. What are the main drivers of decreased NPC from 2024 to 2025?**

334 A. For 2025, the main drivers of decreased NPC were increased coal fuel supply and lower
335 natural gas market prices and power market prices from their 2023 peaks.

336 **Q. What was the change in output for the Company’s coal generating facilities in**
337 **2025?**

338 A. In 2025, the Company’s coal fuel supply stabilized after experiencing constraints and
339 force majeure claims from 2022-2024. Coal generating facilities increased their output
340 from approximately 18 thousand gigawatt-hours (“GWh”) in 2024 to 23 thousand GWh
341 in 2025 as shown in Table 3 above leading to reductions in purchased power volumes

342 and natural gas generation output.

343 **Q. How did lower market power prices decrease NPC in 2025?**

344 A. The average price of market purchases decreased from \$115/MWh in 2024 to
345 \$80/MWh in 2025. When combined with the increase in coal generation output above,
346 market purchase volumes decreased by 2,716 GWh from 2024 to 2025. The overall
347 impact to 2025 NPC was a reduction of \$509 million in market purchase costs.

348 **VII. ADJUSTMENTS RELATED TO FINAL EBA RATES**

349 **Q. Please explain the adjustment to reflect the 2025 EBA Order.**

350 A. The 2025 EBA Order adopted the settlement stipulation between the Company and the
351 Division of Public Utilities with an adjustment of \$4.51 million as a reduction to the
352 EBA.

353 **Q. Please explain the adjustment related to the 2024 EBA.**

354 A. After collection of the authorized EBA in Docket No. 24-035-01 through Schedule 94
355 concluded, \$13,020,077 was over-collected and will be credited to customers in this
356 EBA.

357 **VIII. CONCLUSION**

358 **Q. Please summarize your testimony.**

359 A. The EBA deferral of \$190.6 million, including interest for the calendar year 2025
360 Deferral Period was accurately calculated in compliance with the EBA tariff and
361 previous Commission orders.

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

363 A. Yes.

Rocky Mountain Power
Exhibit RMP___(JP-1)
Docket No. 26-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jack Painter
Monthly EBA Deferral Calculation

May 2026

Utah Energy Balancing Account
 January 1, 2025 - December 31, 2025
 Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor)

Line No.	Reference	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
Actual: Utah Allocated														
1	NPC (2.1)	\$ 91,861,687	\$ 86,812,739	\$ 73,272,670	\$ 68,316,335	\$ 70,603,590	\$ 86,179,812	\$ 112,444,022	\$ 106,271,298	\$ 90,567,045	\$ 69,286,978	\$ 76,485,682	\$ 74,810,888	\$ 1,006,912,746
2	PTC (9.1)	(13,678,589)	(13,599,961)	(14,428,961)	(11,539,132)	(10,602,426)	(8,625,965)	(8,890,482)	(7,312,940)	(7,267,838)	(12,427,417)	(15,335,408)	(22,705,489)	(146,614,608)
3	Wheeling Revenue (4.1)	(8,404,883)	(8,628,193)	(7,259,110)	(4,841,509)	(5,689,303)	(7,016,803)	(8,582,462)	(8,125,073)	(6,586,413)	(6,102,702)	(4,978,235)	(17,929,841)	(94,144,529)
4	Total Σ Lines 1:3	\$ 69,778,214	\$ 64,584,585	\$ 51,584,599	\$ 51,935,694	\$ 54,311,860	\$ 70,337,044	\$ 94,971,078	\$ 90,833,286	\$ 76,712,794	\$ 50,756,859	\$ 56,172,039	\$ 34,175,558	\$ 766,153,610
5	Jurisdictional Sales (5.2)	2,303,221	1,939,829	2,061,580	1,874,104	2,056,241	2,458,108	2,711,847	2,642,817	2,173,398	1,938,586	2,031,821	2,249,587	26,441,140
6	Actual Utah \$/MWh Line 4 / Line 5	\$ 30.30	\$ 33.29	\$ 25.02	\$ 27.71	\$ 26.41	\$ 28.61	\$ 35.02	\$ 34.37	\$ 35.30	\$ 26.18	\$ 27.65	\$ 15.19	\$ 28.98
Base: Utah Allocated														
7	NPC (3.1)(3.2)	\$ 52,896,516	\$ 49,963,481	\$ 51,232,250	\$ 45,519,770	\$ 47,326,041	\$ 55,485,829	\$ 112,824,170	\$ 122,456,740	\$ 66,813,844	\$ 63,667,317	\$ 68,554,411	\$ 87,332,458	\$ 824,072,829
8	PTC (9.1)	(8,852,301)	(8,852,301)	(8,852,301)	(9,368,121)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(11,431,398)	(127,376,208)
9	Wheeling Revenue (4.1)	(4,219,347)	(4,219,347)	(4,219,347)	(5,241,134)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(9,328,280)	(92,525,418)
10	Total Σ Lines 7:9	\$ 39,824,867	\$ 36,891,833	\$ 38,160,602	\$ 30,910,516	\$ 26,566,363	\$ 34,726,151	\$ 92,064,492	\$ 101,697,062	\$ 46,054,166	\$ 42,907,639	\$ 47,794,733	\$ 66,572,780	\$ 604,171,202
11	Jurisdictional Sales (5.2)	2,087,756	1,833,770	1,924,709	1,903,767	2,233,834	2,521,580	2,968,570	2,866,350	2,408,658	2,260,617	2,277,359	2,452,428	27,739,395
12	Base Utah \$/MWh Line 10 / Line 11	\$ 19.08	\$ 20.12	\$ 19.83	\$ 16.24	\$ 11.89	\$ 13.77	\$ 31.01	\$ 35.48	\$ 19.12	\$ 18.98	\$ 20.99	\$ 27.15	\$ 21.78
Deferral:														
13	\$/MWh Differential Line 6 - Line 12	\$ 11.22	\$ 13.18	\$ 5.20	\$ 11.48	\$ 14.52	\$ 14.84	\$ 4.01	\$ (1.11)	\$ 16.18	\$ 7.20	\$ 6.66	\$ (11.95)	\$ 7.20
14	EBA Deferrable Line 5 * Line 13	\$ 25,843,247	\$ 25,559,045	\$ 10,710,281	\$ 21,506,791	\$ 29,857,559	\$ 36,485,002	\$ 10,868,354	\$ (2,932,921)	\$ 35,156,861	\$ 13,961,529	\$ 13,530,385	\$ (26,890,972)	\$ 193,655,162
15	Special Contract Customer Adjustment Subject to Deadband (7.1)	(1,900,740)	(2,581,267)	(312,528)	(150,073)	(1,189,745)	(1,200,982)	(725,154)	(144,289)	(179,065)	(1,320,482)	(1,041,083)	483,007	(10,262,402)
16	Symmetrical Deadband Docket 16-035-33	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
17	Total Special Contract Adjustment Line 15 - Line 16	(1,550,740)	(2,581,267)	(312,528)	(150,073)	(1,189,745)	(1,200,982)	(725,154)	(144,289)	(179,065)	(1,320,482)	(1,041,083)	483,007	(9,912,402)
18	Utah Situs Resource Adjustment (8.1)	445,194	615,721	275,666	919,655	958,781	864,199	1,024,925	443,894	585,080	790,471	498,300	445,516	7,867,402
19	Total Incremental EBA Deferral Σ Lines 14 and Lines 17:18	\$ 24,737,701	\$ 23,593,500	\$ 10,673,419	\$ 22,276,373	\$ 29,626,595	\$ 36,148,219	\$ 11,168,126	\$ (2,633,317)	\$ 35,562,876	\$ 13,431,518	\$ 12,987,602	\$ (25,962,449)	\$ 191,610,162
Energy Balancing Account:														
20	Monthly Interest Rate Note 1	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	
21	Beginning Balance Prior Month Line 27	\$ -	\$ 20,270,499	\$ 43,996,720	\$ 54,867,427	\$ 77,426,590	\$ 107,449,776	\$ 144,139,428	\$ 155,953,577	\$ 153,987,775	\$ 190,296,514	\$ 204,586,012	\$ 218,496,235	\$ -
22	Incremental Deferral Line 19	24,737,701	23,593,500	10,673,419	22,276,373	29,626,595	36,148,219	11,168,126	(2,633,317)	35,562,876	13,431,518	12,987,602	(25,962,449)	191,610,162
23	EVIP Revenue Docket 20-035-34	(12,216)	(9,955)	(22,197)	(14,204)	(18,447)	(23,371)	(27,670)	(28,288)	(27,038)	(28,512)	(27,176)	(27,512)	(266,586)
24	2024 EBA Collection True-Up Docket 24-035-01												(13,020,077)	(13,020,077)
25	2025 EBA Final Order Settlement Docket 25-035-01	(4,510,000)												(4,510,000)
26	Interest Line 20 * (Line 21 + 50% x Line 22)	55,014	142,677	219,484	296,993	415,038	564,805	673,693	695,802	772,901	886,491	949,798	924,756	6,597,453
27	Ending Balance Σ Lines 21:26	\$ 20,270,499	\$ 43,996,720	\$ 54,867,427	\$ 77,426,590	\$ 107,449,776	\$ 144,139,428	\$ 155,953,577	\$ 153,987,775	\$ 190,296,514	\$ 204,586,012	\$ 218,496,235	\$ 180,410,952	\$ 180,410,952
28	Interest Accrued January 1, 2026 through March 31, 2026 Line 27 * (1 + 1.0540% / 12) ^ 3 - Line 27													2,446,524
29	Interest Accrued April 1, 2026 through June 30, 2026 Line 27 and 28 * (1 + 1.05680% / 12) ^ 3 - Line 27 and 28													2,608,886
30	Interest Accrued through Rate Effective Period July 1, 2026 through June 30, 2027													5,092,561
31	Requested EBA Recovery Σ Lines 27:30													\$ 190,558,923

Notes:
 1 Interest rate is from Electric Service Schedule No. 300 due to Docket No. 09-035-15/Order Issued November 14, 2019.