

Rocky Mountain Power  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Direct Testimony of Nikki L. Kobliha

May 2020

1                                   **I.     INTRODUCTION AND QUALIFICATIONS**

2   **Q.     Please state your name, business address, and present position with PacifiCorp.**

3   A.     My name is Nikki L. Kobliha and my business address is 825 NE Multnomah Street,  
4           Suite 1900, Portland, Oregon 97232. I am currently employed as Vice President, Chief  
5           Financial Officer and Treasurer for PacifiCorp. I am testifying for PacifiCorp d/b/a  
6           Rocky Mountain Power (“PacifiCorp” or the “Company”).

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

8   A.     I received a Bachelor of Business Administration with a concentration in Accounting  
9           from the University of Portland in 1994. I became a Certified Public Accountant in  
10          1996. I joined PacifiCorp in 1997 and have taken on roles of increasing responsibility  
11          before being appointed Chief Financial Officer in 2015. I am responsible for all aspects  
12          of PacifiCorp’s finance, accounting, income tax, internal audit, Securities and  
13          Exchange Commission reporting, treasury, credit risk management, pension, and other  
14          investment management activities.

15                               **II.   SUMMARY AND PURPOSE OF TESTIMONY**

16   **Q.     Please summarize the purpose of your testimony.**

17   A.     My testimony covers three areas:

- 18         •       First, I support PacifiCorp’s overall cost of capital recommendation, including  
19               a capital structure with a common equity level of 53.67 percent, the proposed cost of  
20               long-term debt of 4.81 percent, and cost of preferred stock of 6.75 percent.
- 21         •       Second, I explain how PacifiCorp is implementing the effects of the Tax Cuts  
22               and Jobs Act (“TCJA”), as outlined in the orders issued by the Public Service

23 Commission of Utah (“Commission”).<sup>1</sup> Notably, I explain why the Company has  
24 updated the calculation for amortization of Excess Deferred Income Tax (“EDIT”)  
25 balances using the Reverse South Georgia Method (“RSGM”), which results in an  
26 increase in benefits to be amortized in this case than presented in the TCJA proceeding.

27 • Lastly, I explain and support the reasonableness of the Company’s projected  
28 pension costs and inclusion of the prepaid pension balance in rate base.

29 **Q. What is the purpose of the cost of capital recommendation?**

30 A. The Company’s proposed capital structure with a common equity level of 53.67 percent  
31 is required to maintain PacifiCorp’s current credit ratings, which provide for a more  
32 competitive cost of debt. The overall cost of capital facilitates continued access by the  
33 Company to the capital markets over the long term to the benefit of customers. This  
34 capital structure enables the Company’s continued investment in infrastructure to  
35 provide safe and reliable service from new cost-effective energy resources at  
36 reasonable costs.

37 **Q. What overall cost of capital do you recommend for PacifiCorp?**

38 A. PacifiCorp proposes an overall cost of capital of 7.70 percent. This cost includes the  
39 return on equity recommendation of 10.20 percent, supported by the direct testimony  
40 of Ms. Ann E. Bulkley, and the capital structure and costs shown in Table 1.

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<sup>1</sup> *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: “An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018,”* Docket No. 17-035-69, Order (April 27, 2018) & Order Approving Settlement Stipulation (Nov. 9, 2018).

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**Table 1: Overall Cost of Capital**

Component	\$m	% of Total	Cost %	Weighted
Long-Term Debt	\$ 8,423	46.32%	4.81%	2.23%
Preferred Stock	\$ 2	0.01%	6.75%	0.00%
Common Stock Equity	\$ 9,759	53.67%	10.20%	5.47%
	<u>\$ 18,184</u>	<u>100.00%</u>		<u>7.70%</u>

42 **Q. What time period does your analysis cover?**

43 A. The capital structure for the Company is measured over the 12-month period ending  
 44 December 31, 2021, the approved test period in this proceeding, using an average of  
 45 the five quarter-ending balances, based on known and measurable changes through  
 46 December 31, 2021. Similarly, the costs of the long-term debt and preferred stock are  
 47 an average of the costs measured for each of the five quarter-ending balances spanning  
 48 the calendar 2021 test period, using the Company's actual costs adjusted for known  
 49 and measurable changes through December 31, 2021.

50 **III. FINANCING OVERVIEW**

51 **Q. Please explain PacifiCorp's need for and sources of new capital.**

52 A. PacifiCorp requires capital to meet its customers' needs for new cost-effective  
 53 transmission and renewable generation, increased reliability, improved power delivery,  
 54 and safe operations. PacifiCorp also needs new capital to fund long-term debt  
 55 maturities.

56 As described in the testimony of Mr. Gary W. Hoogeveen, through the Energy  
 57 Vision 2020 project, PacifiCorp is in the process of completing the repowering of its  
 58 wind generation fleet and significantly increasing its wind generation and transmission  
 59 capacity. PacifiCorp expects to spend approximately \$3.6 billion for investments in  
 60 renewable energy projects and related transmission through calendar year 2021. This

61 capital spending will require PacifiCorp to raise funds by issuing new long-term debt  
62 in the capital markets, retaining earnings, and if needed, obtaining new capital  
63 contributions from its parent company, Berkshire Hathaway Energy Company  
64 (“BHE”).

65 **Q. How does PacifiCorp finance its electric utility operations?**

66 A. Generally, PacifiCorp finances its regulated utility operations using a mix of debt and  
67 common equity capital of approximately 48/52 percent, respectively. During periods  
68 of significant capital expenditures, as expected to continue now through calendar year-  
69 end 2023 for potential new investments identified in the 2019 IRP action plan,<sup>2</sup> the  
70 Company will need to maintain an average common equity component in excess of  
71 52 percent to maintain its credit rating and finance the debt component of the capital  
72 structure at the lowest reasonable cost to customers. Maintaining the Company’s credit  
73 rating will provide more flexibility on the type and timing of debt financing, better  
74 access to capital markets, a more competitive cost of debt, and over the long-run, more  
75 stable credit ratings. In addition, PacifiCorp needs a greater common equity component  
76 to offset various adjustments that rating agencies make to the debt component of the  
77 Company’s published financial statements and to mitigate the impact the TCJA has had  
78 on the Company’s credit metrics. I discuss these adjustments in greater detail later in  
79 my testimony.

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<sup>2</sup> *PacifiCorp’s 2019 Integrated Resource Plan*, Docket No. 19-035-02, Chapter 1 – Executive Summary, p. 22 (Oct. 18, 2019).

80 **Q. How does PacifiCorp determine the levels of common equity, debt, and preferred**  
81 **stock to include in its capital structure?**

82 A. As a regulated public utility, PacifiCorp has a duty and an obligation to provide safe,  
83 adequate, and reliable service to customers in its Utah service area while prudently  
84 balancing cost and risk. Major capital expenditures are required in the near-term for  
85 new plant investment to fulfill its service obligation, including capital expenditures for  
86 repowering wind projects, new wind, and transmission. These capital investments also  
87 have associated operating and maintenance costs. As part of its annual business  
88 planning process, PacifiCorp reviews all of its estimated cash inflows and outflows to  
89 determine the amount, timing, and type of new financing required to support these  
90 activities and provide for financial results and credit ratings that balance the cost of  
91 capital with continued access to the financial markets.

92 **Q. How does PacifiCorp manage its dividends to BHE?**

93 A. PacifiCorp benefits from its affiliation with BHE as there is no dividend requirement.  
94 Historically, PacifiCorp has paid dividends to BHE to manage the common equity  
95 component of the capital structure and keep the Company's overall cost of capital at a  
96 prudent level. In major capital investment periods, PacifiCorp is able to retain earnings  
97 to help finance capital investments and forgo paying dividends to BHE. For example,  
98 following BHE's acquisition of PacifiCorp in 2006, PacifiCorp managed the capital  
99 structure through the timing and amount of long-term debt issuances and capital  
100 contributions from BHE, while forgoing any common dividends for nearly five years.  
101 At other times, absent the payment of dividends, retention of earnings could cause the  
102 percentage of common equity to grow beyond the level necessary to support the current

103 credit ratings. Accordingly, dividend payments can be necessary, in combination with  
104 debt issuances, to maintain the appropriate percentage of equity in PacifiCorp's capital  
105 structure. With the increased capital investment required for the Energy Vision 2020  
106 project and other capital expenditures, however, the proposed capital structure in this  
107 case anticipates no additional common dividend payments by PacifiCorp to BHE  
108 through calendar year 2021.

109 **Q. What type of debt does PacifiCorp use in meeting its financing requirements?**

110 A. PacifiCorp has completed the majority of its recent long-term financing using secured  
111 first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989.  
112 Exhibit RMP\_\_\_\_(NLK-1), Pro forma Cost of Long-Term Debt, shows that, over the  
113 test period, PacifiCorp is projected to have an average of approximately \$8.4 billion of  
114 first mortgage bonds outstanding, with an average cost of 4.81 percent. Presently, all  
115 outstanding first mortgage bonds bear interest at fixed rates. Proceeds from the issuance  
116 of the first mortgage bonds (and other financing instruments) are used to finance utility  
117 operations.

118 Another important source of financing in the past has been the tax-exempt  
119 financing associated with certain qualifying equipment at power generation plants.  
120 Under arrangements with local counties and other tax-exempt entities, these entities  
121 issue securities, and PacifiCorp borrows the proceeds of these issuances and pledges  
122 its credit quality to repay the debt to take advantage of the tax-exempt status of the  
123 financing. During the test period, PacifiCorp's tax-exempt portfolio is projected to be  
124 approximately \$218 million, with an average cost of 1.61 percent, including the cost of  
125 issuance and remarketing.

**Credit Ratings**

**Q. What are PacifiCorp's current credit ratings?**

A. PacifiCorp's current ratings are shown in Table 2.

**Table 2: PacifiCorp Credit Ratings**

	Moody's	Standard & Poor's
Senior Secured Debt	A1	A+
Senior Unsecured Debt	A3	A
Outlook	Stable	Stable

**Q. How does the maintenance of PacifiCorp's current credit rating benefit customers?**

A. First, the credit rating of a utility has a direct impact on the price that a utility pays to attract the capital necessary to support its current and future operating needs. Many institutional investors have fiduciary responsibilities to their clients, and are typically not permitted to purchase non-investment grade (*i.e.*, rated below Baa3/BBB-) securities or in some cases even securities rated below single A. A solid credit rating directly benefits customers by reducing the immediate and future borrowing costs related to the financing needed to support regulatory obligations.

Second, credit ratings are an estimate of the probability of default by the issuer on each rated security. Lower ratings equate to higher risks and higher costs of debt. The Great Recession of 2008 to 2009 provides a clear and compelling example of the benefits of the Company's credit rating because PacifiCorp was able to issue new long-term debt in the midst of the financial turmoil. Other lower-rated utilities were shut out of the market and could not obtain new capital.



145 Third, PacifiCorp has a near-constant need for short-term liquidity as well as  
146 periodic long-term debt issuances. PacifiCorp pays significant amounts daily to  
147 suppliers whom we count on to provide necessary goods and services, such as fuel,  
148 energy, and inventory. Being unable to access funds can risk the successful completion  
149 of necessary capital infrastructure projects and would increase the chance of outages  
150 and service failures over the long term.

151 PacifiCorp's creditworthiness, as reflected in its credit ratings, will strongly  
152 influence its ability to attract capital in the competitive markets and the resulting costs  
153 of that capital.

154 **Q. Please provide examples where poor credit ratings hurt a utility's flexibility in the**  
155 **credit markets.**

156 A. During the Great Recession in 2008, Arizona Public Service Company (rated  
157 Baa2/BBB- at that time) filed a letter with the Arizona Corporation Commission in  
158 October 2008 stating that the commercial paper market was completely closed to it and  
159 it likely could not successfully issue long-term debt.<sup>3</sup>

160 Further, those issuers who could access the markets paid rates well above the  
161 levels that PacifiCorp was able to obtain. For example, PacifiCorp issued new 10-year  
162 and 30-year long-term debt in January 2009 with 5.50 percent and 6.00 percent coupon  
163 rates, respectively. Subsequently, Puget Sound Energy (rated Baa2/A- at that time)  
164 issued new seven-year debt at a credit spread over Treasuries of 480.3 basis points  
165 resulting in a 6.75 percent coupon.

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<sup>3</sup> See Exhibit RMP\_\_\_\_(NLK-2).

166 **Q. Can regulatory actions or orders affect PacifiCorp's credit rating?**

167 A. Yes. Regulated utilities such as PacifiCorp are unique in that they cannot unilaterally  
168 set the price for their services. The financial integrity of a regulated utility is largely a  
169 result of the prudence of utility operations and the corresponding prices set by  
170 regulators. Rates are established by regulators to permit the utility to recover prudently  
171 incurred operating expenses and a reasonable opportunity to earn a fair return on the  
172 capital invested.

173 Rating agencies and investors have a keen understanding of the importance of  
174 regulatory outcomes. For example, Standard & Poor's ("S&P") has opined on the  
175 correlation between regulatory outcomes and credit ratings, concluding:

176 Although not common, rate case outcomes can sometimes lead  
177 directly to a change in our opinion of creditworthiness. Often it's a  
178 case that takes on greater importance because of the issues being  
179 litigated. For example, in 2010, we downgraded Florida Power &  
180 Light and its affiliates following a Florida Public Service  
181 Commission rate ruling that attracted attention due to drastic  
182 changes to settled practices on rate case particulars like depreciation  
183 rates. More recently, in June 2016, we downgraded Central Hudson  
184 Electric & Gas due to our revised opinion of regulatory risk. While  
185 that reflected the company's own management of regulatory risk, it  
186 was prompted in part by other rate case decisions in New York that  
187 highlighted the overall risk in the state.<sup>4</sup>

188 Similarly, Moody's recently issued a credit opinion for PacifiCorp, concluding:

189 The stable outlook incorporates our expectation that PacifiCorp will  
190 continue to receive reasonable regulatory treatment, and that  
191 funding requirements will be financed in a manner consistent with  
192 management's commitment to maintain a healthy financial profile.

193  
194 ... The ratings could be downgraded if PacifiCorp's capital  
195 expenditures are funded in a manner inconsistent with its current  
196 financial profile, or if adverse regulatory rulings lower its credit

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<sup>4</sup> S&P Ratings Direct, *Assessing U.S. Investor-Owned Utility Regulatory Environments* (Aug. 10, 2016), at 4.

197 metrics, as demonstrated for example, by a ratio of CFO pre-  
198 W/C/Debt sustained below 20%.<sup>5</sup>

199 As discussed in the testimony of Ms. Bulkley, Section VIII, Regulatory and  
200 Business Risk, the regulatory environment and the rate decisions by utility  
201 commissions have a direct and significant impact on the financial condition of utilities.

202 **Q. How does the maintenance of PacifiCorp's current credit ratings benefit**  
203 **customers?**

204 A. PacifiCorp is in the midst of a period of major capital spending and investing in cost-  
205 effective infrastructure to provide electric service that is reliable, clean, and affordable.  
206 If PacifiCorp does not have consistent access to the capital markets at reasonable costs,  
207 these borrowings and the resulting costs of building new facilities become more  
208 expensive than they otherwise would be. The inability to access financial markets can  
209 threaten the completion of necessary projects and can impact system reliability and  
210 customer safety. Maintaining the current single A credit rating makes it more likely  
211 PacifiCorp will have access to the capital markets at reasonable costs even during  
212 periods of financial turmoil.

213 **Q. Can you provide an example of how the current ratings have benefited customers?**

214 A. Yes. One example is PacifiCorp's ability to significantly reduce its cost of long-term  
215 debt primarily through obtaining new financings at very attractive interest rates. The  
216 lower cost of debt benefits customers through a lower overall rate of return and lower  
217 revenue requirement.

218 To determine the savings realized from maintaining a higher credit rating, in  
219 Exhibit RMP\_\_\_\_(NLK-3) New Debt Issue Spreads, I compare the actual effective

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<sup>5</sup> Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 27, 2019), at 2.

interest rate on the Company's existing long-term debt through March 31, 2020, which was issued since its acquisition by BHE in 2006, comprising 15 series of debt, to what the effective interest rate would have been with a BBB credit rating. The spread of each issuance was changed to match what a BBB rated utility achieved at about the same point in time that PacifiCorp issued the debt. The total result for the 15 series of debt averaging \$6.0 billion, would have been an effective average interest rate of approximately 5.31 percent or 55 basis points higher than the actual effective interest rate. Combined with the existing pre-acquisition debt, the resulting overall cost of long-term debt would increase to 5.20 percent if the Company had a BBB rating. PacifiCorp is currently projecting an overall cost of long-term debt of 4.81 percent, or approximately 39 basis points lower than it might have otherwise been under the scenario I described above.

Table 3 below shows the reduction in the Company's cost of long-term debt since 2009.

**Table 3: PacifiCorp's Cost of Long-Term Debt**

	2020 GRC Effective 2021	13-035-184 August 2014	11-035-200 Sept 2012	10-035-124 Sept 2011	09-035-23 Feb 2010	08-035-38 April 2009
Cost of Long-Term Debt	4.81%	5.2%	5.37%	5.71%	5.98%	6.02%

PacifiCorp's customers have benefited from a 121 basis points (1.21 percent) reduction in the Company's cost of long-term debt. The Company estimates that this reduction in the average cost of debt since 2009 results in a decrease of approximately \$44 million in the revenue requirement in the current case. Customers have also benefited from the

239 Company's ability to negotiate lower underwriting fees on long-term debt issuances  
240 through BHE's global underwriting fee position.

241 **Q. Are there other identifiable advantages to a favorable rating?**

242 A. Yes. Higher-rated companies have greater access to the long-term markets for power  
243 purchases and sales. This access provides these companies with more alternatives to  
244 meet the current and future load requirements of their customers. Additionally, a  
245 company with strong ratings will often avoid having to meet costly collateral  
246 requirements that are typically imposed on lower-rated companies when securing  
247 power in these markets.

248 In my opinion, maintaining the current single A rating provides the best balance  
249 between costs and continued access to the capital markets, which is necessary to fund  
250 capital projects for the benefit of customers.

251 **Q. Is the proposed capital structure consistent with PacifiCorp's current credit**  
252 **rating?**

253 A. Yes. This capital structure is intended to help the Company deliver its required capital  
254 expenditures and achieve financial metrics that will meet rating agency expectations.

255 **Q. Does PacifiCorp's credit rating benefit because of BHE and its parent Berkshire**  
256 **Hathaway Inc.?**

257 A. Yes. Although ring-fenced, PacifiCorp's credit ratios have been weak for its ratings  
258 level. PacifiCorp has been able to sustain its ratings in part through the acquisition by  
259 BHE and its parent, Berkshire Hathaway Inc. S&P was very clear on this point in its  
260 March 2019 assessment of PacifiCorp:

261 Under our group rating methodology, we consider PacifiCorp to be  
262 a core subsidiary of BHE with a group credit profile of 'a'. The core

status reflects our view that PacifiCorp is highly unlikely to be sold, has strong long-term commitment from senior management, is successful at what it does, and contributes meaningfully to the group. At the same time, we consider PacifiCorp as potentially insulated, with existing insulation measures that would support a one-notch separation between PacifiCorp and parent BHE. Given its core subsidiary status and BHE's group credit profile of 'a', the issuer credit rating on PacifiCorp is 'A'.<sup>6</sup>

Moody's states in their June 2019 credit opinion of PacifiCorp:

PacifiCorp benefits from its affiliation with Berkshire Hathaway Inc., which requires no regular dividends from PacifiCorp or BHE. From a credit perspective, the company's ability to retain its earnings as an entity that is privately held, particularly by a deep-pocketed sponsor like Berkshire Hathaway Inc., is an advantage over most other investor owned utilities that are typically held to a regular dividend to their shareholders. PacifiCorp currently pays dividends that are sized to manage its equity ratio (as measured by unadjusted equity to equity plus long term debt) around its allowed levels of slightly higher than 50% (regulations restrict dividends if this ratio falls below 44%). As of December 2018, PacifiCorp reports its actual equity percentage, as calculated under this test, was 54%. Furthermore, BHE has placed PacifiCorp in a ring-fencing structure that restricts dividends if PacifiCorp's ratings fall to non-investment grade.<sup>7</sup>

These examples are evidence of the credit rating benefit resulting from BHE's ownership of PacifiCorp.

**Q. How does the TCJA impact PacifiCorp's credit rating?**

A. The three main rating agencies have issued reports on the impact of tax reform on U.S. utilities and their holding companies and believe that tax reform will be unfavorable to utilities in the near term but with regulatory support for a stronger capital structure, highly rated utilities may retain positive credit ratings. For example, S&P determined:

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<sup>6</sup> S&P Ratings Direct, *PacifiCorp* (Mar. 15, 2019), at 9.

<sup>7</sup> Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 27, 2019), at 6.

294 The impact could be sharpened or softened by regulators depending  
295 on how much they want to lower utility rates immediately instead of  
296 using some of the lower revenue requirement from tax reform to  
297 allow the utility to retain the cash for infrastructure investment or  
298 other expenses. Regulators must also recognize that tax reform is a  
299 strain on utility credit quality, and we expect companies to request  
300 stronger capital structures and other means to offset some of the  
301 negative impact.<sup>8</sup>

302 The Company has passed through partial benefits related to tax reform  
303 and is planning to pass through all of the remaining benefits in its jurisdictions; thus  
304 the negative impact to the Company's key credit metric (Moody's CFO pre-W/C/Debt)  
305 has not yet been fully realized. Absent regulatory support for a stronger capital  
306 structure, however, the Company's cash from operations will likely fall below levels  
307 where it can maintain the minimum 20 percent expectation for this credit metric, which  
308 could increase the likelihood of a downgrade. Moody's states in their January 24, 2018  
309 Sector Comment on Tax Reform:

310 Tax reform mainly affects companies that already had limited  
311 cushion in their credit profile. The tax reform usually resulted in a  
312 further 150-250 bps drop in CFO pre-W/C/debt.  
313

314 Moody's expects that most utilities will attempt to manage any  
315 negative financial implications of tax reform through regulatory  
316 channels. Corporate financial policies could also change. The  
317 actions taken by utilities will be incorporated into our credit analysis  
318 on a prospective basis. It is conceivable that some companies will  
319 sufficiently defend their credit profiles.

320 In practice, we believe that most companies will actively manage  
321 their cash flow to debt ratios by issuing more equity or obtaining  
322 relief by working through regulatory channels.<sup>9</sup>

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<sup>8</sup> S&P Ratings Direct, *U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound* (Jan. 24, 2018), at 5.

<sup>9</sup> Moody's, *Tax Reform is Credit Negative for Sector, But Impact Varies by Company* (Jan. 24, 2018), at 3.

323 **Q. Have other public service commissions recognized that the TCJA has had an**  
324 **adverse impact on utility cash flows and credit ratings?**

325 A. Yes. In a recent decision involving Questar Gas Company dba Dominion Energy  
326 Wyoming (“Dominion”), the Wyoming Public Service Commission (“Wyoming PSC”) approved a modification to the stipulation in the Questar-Dominion merger case. The  
327 original stipulation required Dominion to maintain an equity ratio in the range of 50-  
328 55 percent, and the modification partially lifted the 55 percent cap on the equity ratio.  
329 In approving the modification, the Wyoming PSC found that an “unintended  
330 consequence of the [TCJA] is that it has put pressure on Dominion’s credit metrics,”  
331 by reducing cash flow and negatively affecting the Funds From Operations metric. The  
332 Wyoming PSC explained that “a deterioration of the Company’s credit metrics could  
333 result in a downgrade in Dominion’s credit rating, which would in turn result in a higher  
334 cost of debt for the Company and its customers.” The Wyoming PSC also noted that,  
335 to improve its credit metrics in response to the TCJA and avoid a downgrade, Dominion  
336 believed it was necessary to issue additional equity to replace debt potentially  
337 exceeding the 55 percent equity cap. The Wyoming PSC approved the requested  
338 modification, finding it to be in the public interest.

340 Similarly, in February 2019, the Public Utility Commission of Oregon (“Oregon  
341 PUC”) adopted a staff memo recommending approval of an application by Avista Corp.  
342 (Avista) to issue stock.<sup>10</sup> Staff’s memo included the following statements about the  
343 TCJA and the importance of maintaining strong credit ratings:

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<sup>10</sup> *In the matter of Avista Corp., dba Avista Util., Application for Authorization to Issue 3,500,000 Shares of Common Stock*, Docket No. UF 4308, Order No. 19-067 (Feb. 28, 2019).



Staff finds that the Tax Cuts and Jobs Act of 2017 created unanticipated stresses on [Avista's] credit ratings. The requested authorization signals to rating agencies that the Company is committed to the equity portion of its capital structure. However, it is Staff's finding that restoring a notch in credit ratings involves more than just remedying the cause for the downgrade. On December 21, 2018, Moody's stated, "Avista's credit profile reflects its low-risk vertically integrated electric and gas utility business, regulatory uncertainty in WA and the expected negative cash flow impact of tax reform." Authorization herein as recommended by Staff starts the process of addressing rating agency concerns and restoring a positive credit outlook.<sup>11</sup>

In July 2019, the Oregon PUC approved Avista's application to issue debt securities, adopting Staff's memo stating that, as a result of the TCJA, "[r]aising the Company's credit ratings back up a notch will require hard work and persistence on the part of Avista's finance group as well as a supportive regulatory environment and achieving target metrics."<sup>12</sup>

#### **Rating Agency Debt Imputations**

**Q. Is PacifiCorp subject to rating agency debt imputation associated with power purchase agreements ("PPAs")?**

**A.** Yes. Rating agencies and financial analysts consider PPAs to be debt-like and will impute debt and related interest when calculating financial ratios. For example, S&P will adjust PacifiCorp's published financial results and impute debt balances and interest expense resulting from PPAs when assessing creditworthiness. They do so to obtain a more accurate assessment of a Company's financial commitments and fixed payments. S&P Ratings Direct November 19, 2013, details its view of the debt aspects

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<sup>11</sup> *Id.* at Appendix A, p.4; see also *In the matter of Portland Gen. Elec. Co., Request for Authority to Extend the Maturity of an Existing \$500 Million Revolving Credit Agreement*, Docket No. UF 4272(3), Order No. 19-025 at Appendix A, p.9. (Jan. 23, 2019) (including similar observations regarding an application by Portland General Electric).

<sup>12</sup> *In the matter of Avista Corp., dba Avista Util., Application for Authorization to Issue and Sell \$600,000,000 of Debt Securities*, Docket No. UF 4313, Order No. 19-249 (July 30, 2019).

371 of PPAs and other debt imputations, and is included as Confidential Exhibit  
372 RMP\_\_\_\_(NLK-4).

373 **Q. How does this impact PacifiCorp?**

374 A. In its most recent evaluation of PacifiCorp, S&P added approximately \$479 million of  
375 additional debt and \$21 million of related interest expense to the Company's debt and  
376 coverage tests for PPAs and other liabilities of the Company that are considered to be  
377 debt-like by S&P.

378 **Q. How does inclusion of the PPA-related debt and these other adjustments affect**  
379 **PacifiCorp's capital structure as S&P reviews the Company's credit metrics?**

380 A. Negatively. By including the imputed debt resulting from PPAs and these other  
381 adjustments, PacifiCorp's capital structure has a lower equity component as a corollary  
382 to the higher debt component, lower coverage ratios, and reduced financial flexibility  
383 than what might otherwise appear to be the case from a review of the book value capital  
384 structure. For example, as shown in Table 4, if one were to apply the total \$479 million  
385 amount of debt adjustments that S&P most recently made to PacifiCorp's proposed  
386 capital structure in this case, the resulting common equity percentage would decline  
387 from 53.67 percent to 52.29 percent. The corresponding higher average adjusted debt  
388 percentage of 47.70 percent over the test period reflects an adjusted capital structure  
389 that approximates the 48/52 percent baseline mix of debt and common equity capital  
390 that PacifiCorp targets.

391

**Table 4: Rating Agency Adjusted Capital**

	Proposed Cap Structure		Rating  Agency Adjmts	Adjusted Cap Structure	
	Book Values	% of Total		Book Values	% of Total
Long-Term Debt	\$ 8,423	46.32%	\$ 479	\$ 8,902	47.70%
Preferred Stock		0.01%	(1)	1	0.01%
Common Equity	9,759	53.67%	0	9,759	52.29%
	\$ 18,184	100.00%	\$ 478	\$ 18,662	100.00%

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#### IV. CAPITAL STRUCTURE DETERMINATION

393 **Q. How did the Company determine its recommended capital structure?**

394 A. The capital structure is based on the actual capital structure at March 31, 2020, and  
 395 forecasted capital activity, including known and measurable changes, through  
 396 December 31, 2021. PacifiCorp averaged the five quarter-end capital structures  
 397 measured beginning at December 31, 2020, and concluding with December 31, 2021,  
 398 resulting in a capital structure with an equity component of 53.67 percent. The capital  
 399 activity includes known maturities of certain debt issues that were outstanding at March  
 400 31, 2020, and subsequent issuances of long-term debt. The known and measurable  
 401 changes represent forecasted capital activity since March 31, 2020.

402 **Q. Why does the Company propose a capital structure calculated using a five-quarter**  
 403 **average?**

404 A. This approach smooths volatility in the capital structure, which will fluctuate as the  
 405 Company expends capital, issues or retires debt, retains earnings, or declares dividends.  
 406 This approach is consistent with the Company's previous general rate cases beginning  
 407 with Docket No. 09-035-23.

**Q. How does the Company's proposed capital structure compare to recent actual capital structures and to the capital structure authorized in PacifiCorp's last general rate case, Docket No. 13-035-184 ("2014 Rate Case")?**

A. The capital structures are compared in Table 5 below.

**Table 5: Forecast and Actual Capital Structures**

<b>PacifiCorp's Comparison of % Capital Structures</b>						
	Dec 31, 2021 Forecast*	Dec 31, 2020 Forecast*	Dec 31, 2019 Actual*	Dec 31, 2018 Actual*	Dec 31, 2017 Actual*	13-035-184 Capital Structure
Long-Term Debt	46.32 %	48.39 %	48.36 %	47.89 %	48.49 %	48.55 %
Preferred Stock	0.01 %	0.01 %	0.02 %	0.02 %	0.02 %	0.02 %
Common Equity	53.67 %	51.60 %	51.62 %	52.09 %	51.49 %	51.43 %
Totals	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

\*Five quarter-end average % Capital Structure calculated for trailing 12 month period ending

The percentage increase in the common equity component of the capital structure from the actual December 31, 2019 five-quarter average to that projected for the 2021 forecast test period is due to earnings offset by debt issuances and the forgoing of any common dividend payments in 2020 and 2021. Further, both of the Company's projected capital structures for 2020 and 2021 contain a higher common equity component than what was approved by the Commission in the 2014 Rate Case. As discussed above, PacifiCorp's increased capital investment requirements and ratings pressure caused by the TCJA require PacifiCorp to increase the equity in its capital structure to maintain its current ratings.

**Q. How did you calculate the Company's embedded costs of long-term debt and preferred stock?**

A. Consistent with my determination of the percentage capital structure discussed previously, I have similarly calculated the embedded costs of debt and preferred stock

426 as an average of the five quarter-end cost calculations spanning the test period,  
427 beginning at December 31, 2020, and concluding with December 31, 2021.

428 **Q. Please explain the cost of long-term debt calculation.**

429 A. I calculated the embedded cost of debt using the methodology relied upon in the  
430 Company's previous rate cases in Utah and other jurisdictions. More specifically, I  
431 calculated the cost of debt by issue, based on each debt series' interest rate and net  
432 proceeds at the issuance date, to produce a bond yield to maturity for each series of  
433 debt outstanding as of each of the five quarter-ending dates spanning the 12-month  
434 calendar 2021 test period. It should be noted that in the event a bond was issued to  
435 refinance a higher cost bond, the pre-tax premium and unamortized costs, if any,  
436 associated with the refinancing were subtracted from the net proceeds of the bonds that  
437 were issued. Each bond yield was then multiplied by the principal amount outstanding  
438 of each debt issue, resulting in an annualized cost of each debt issue. Aggregating the  
439 annual cost of each debt issue produces the total annualized cost of debt. Dividing the  
440 total annualized cost of debt by the total principal amount of debt outstanding produces  
441 the weighted average cost for all debt issues.

442 **Q. Please describe the changes to the amount of outstanding long-term debt between**  
443 **December 31, 2019, and December 31, 2021.**

444 A. Approximately \$38 million and \$420 million of the Company's variable and fixed rate  
445 long-term debt, respectively, will mature during this period, and I have therefore  
446 removed this debt when appropriate in the determination of the proposed average cost  
447 of debt. Also, as reflected in Exhibit RMP\_\_\_\_(NLK-1), Pro forma Cost of Long-Term  
448 Debt, are the new first mortgage bond issuances made by the Company in April 2020,

449 consisting of a \$400 million 10-year 2.70% series and a \$600 million 31-year term  
450 3.30% series. The total issuance costs reflected for each of these two recent new debt  
451 issuances in Exhibit RMP\_\_\_\_(NLK-1), Pro forma Cost of Long-Term Debt, are based  
452 both on actual and estimated costs. The Company currently anticipates no further long-  
453 term debt issuances will be necessary through December 31, 2021.

454 **Q. A portion of the securities in PacifiCorp's debt portfolio bears variable rates.**  
455 **What is the basis for the projected interest rates used by PacifiCorp?**

456 A. The Company's variable rate long-term debt in this case is in the form of tax-exempt  
457 debt. Exhibit RMP\_\_\_\_(NLK-5), Variable Rate Pollution Control Revenue Bonds,  
458 shows that, on average, these securities have been trading at approximately 84 percent  
459 of the 30-day London Inter Bank Offer Rate ("LIBOR") for the period January 2000  
460 through December 2019. Therefore, the Company has applied a factor of 84 percent to  
461 the forward 30-day LIBOR rate as of each of the five quarter-ending dates spanning  
462 calendar year 2021 and then added the respective credit facility and remarketing fees  
463 for each floating rate tax-exempt bond outstanding during the period. Credit facility  
464 and remarketing fees are included in the interest component because these are costs  
465 which contribute directly to the interest rate on the securities and are charged to interest  
466 expense. This method is consistent with the Company's past practices when  
467 determining the cost of debt in previous Utah general rate cases as well as in other  
468 states that regulate PacifiCorp.

469 **Q. How did you calculate the embedded cost of preferred stock?**

470 A. The embedded cost of preferred stock was calculated by first determining the cost of  
471 money for each issue. I began by dividing the annual dividend per share by the per

share net proceeds for each series of preferred stock. The resulting rate associated with each series was then multiplied by the total par or stated value outstanding for each issue to yield the annualized cost for each issue. The sum of annualized costs for each issue produces the total annual cost for the entire preferred stock portfolio. I then divided the total annual cost by the total amount of preferred stock outstanding to produce the weighted average cost for all issues. The result is PacifiCorp's embedded cost of preferred stock.

#### **Embedded Cost of Long-Term Debt**

**Q. What is PacifiCorp's embedded cost of long-term debt?**

A. The cost of long-term debt is 4.81 percent, as shown in Exhibit RMP\_\_\_\_(NLK-1), Pro forma Cost of Long-Term Debt.

#### **Embedded Cost of Preferred Stock**

**Q. What is PacifiCorp's embedded cost of preferred stock?**

A. Exhibit RMP\_\_\_\_(NLK-6), Cost of Preferred Stock, shows the embedded costs of preferred stock to be 6.75 percent.

### **VI. IMPLEMENTATION OF TCJA TAX BENEFITS IN RATES**

**Q. How does PacifiCorp propose to include the benefits of the TCJA's lower tax rate in this proceeding?**

A. PacifiCorp included the tax benefits by: (1) embedding the lower tax rate in base rates as discussed in the testimony of Mr. Steven R. McDougal; (2) including a rate base deduction for unamortized protected Excess Deferred Income Tax ("EDIT") and lowering income tax expense for the annual level of amortization; and (3) returning to customers the tax benefits deferred as of December 31, 2020.

495 These actions are consistent with the Commission's decision in Docket No. 17-035-  
496 69.<sup>13</sup>

497 **Q. Please quantify the TCJA balances deferred as of December 31, 2020, that will be**  
498 **refunded to customers.**

499 A. The total amount of deferred TCJA tax benefits projected to be available as of  
500 December 31, 2020, is \$142.6 million. PacifiCorp's proposal to return this balance to  
501 customers is explained in the direct testimony of Mr. McDougal.

502 **Q. How do the EDIT balances presented in this case differ from the balances in the**  
503 **November 9, 2018, Order Approving Settlement Stipulation in Docket No. 17-035-**  
504 **69?**

505 A. As discussed in the Company's March 25, 2020 supplemental notice in Docket No. 17-  
506 035-69, the Company has made two changes.

507 First, while total EDIT has not changed, PacifiCorp made a correction in the  
508 classification between protected and non-protected EDIT. The misclassification was  
509 identified during the process of extracting non-protected property EDIT balances from  
510 the Company's tax fixed asset system so that they could be used in the manner as  
511 described in the Commission-approved stipulation. The correction resulted in more  
512 EDIT classified as non-protected and less classified as protected.

513 Second, PacifiCorp will be using the RSGM to amortize protected EDIT,  
514 retroactive to January 1, 2018, because the Company's books and underlying records  
515 do not contain the necessary vintage account data to use the Average Rate Assumption

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<sup>13</sup> *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018,"* Docket No. 17-035-69, Order (April 27, 2018) & Order Approving Settlement Stipulation (Nov. 9, 2018).



516 Method ("ARAM") as originally contemplated. The amortization of PacifiCorp's  
517 protected EDIT for 2018, 2019, and 2020 is greater under the RSGM as compared to  
518 the Company's ARAM projections.

519 **The Reverse South Georgia Method**

520 **Q. Please explain why PacifiCorp's books and underlying records do not contain the**  
521 **necessary vintage account data to use the ARAM.**

522 A. For some assets and in certain circumstances, PacifiCorp records situs book  
523 depreciation on system-allocated assets. For background, PacifiCorp depreciates  
524 system-allocated assets using a base composite life; this base level of book depreciation  
525 is system-allocated. An incremental amount of book depreciation is calculated for  
526 jurisdictions that approve a composite life different from the base or otherwise approve  
527 accelerated book depreciation for system-allocated assets; this incremental amount of  
528 book depreciation is situs-allocated.

529 To use the ARAM, book depreciation is required at a jurisdictional level by  
530 vintage and tax class to have the necessary vintage account data. Because book  
531 depreciation is not maintained at this level for book accounting purposes, PacifiCorp  
532 relies on its tax fixed asset system to produce the necessary vintage account data for  
533 tax purposes by performing a procedure to allocate book depreciation.

534 As presently configured, the book depreciation allocation procedure cannot  
535 process situs book depreciation on system-allocated assets in a manner that impacts  
536 only the vintage account data of the jurisdiction to which the situs book depreciation  
537 inures. As a result, the situs book depreciation must be accounted for separately as a

538 tax class of its own, thereby rendering the jurisdictional vintage account data to which  
539 the EDIT is actually attached incomplete for the purposes of using the ARAM.

540 **Q. How are the issues with situs book depreciation addressed by the RSGM?**

541 A. Unlike the ARAM, book depreciation is not required at the jurisdictional level by  
542 vintage and tax class for amortization of EDIT when using the RSGM. The RSGM  
543 requires only the use of a remaining regulatory life for an asset or group of assets to  
544 amortize the EDIT on a straight-line basis.

545 To implement the RSGM, PacifiCorp categorized Utah-allocated protected  
546 EDIT at the level of detail presented in the Company's most recently filed depreciation  
547 study. The protected EDIT is then amortized straight-line over Utah's approved  
548 remaining regulatory life for each respective asset or group of assets. For tax years  
549 2018 to 2020, the remaining lives are based on the 2013 depreciation study.<sup>14</sup>  
550 Beginning in 2021, the remaining lives will be updated to match those in the Company's  
551 2018 depreciation study in Docket No. 18-035-36, which was approved on April 20,  
552 2020, and then again for each depreciation study approved thereafter.<sup>15</sup> If the  
553 Commission approves regulatory lives different from those approved in the 2018  
554 depreciation study or as otherwise proposed in this case, the protected EDIT  
555 amortization included in this case will need to be updated accordingly.

556 **Q. Do PacifiCorp's facts meet the statutory requirements for using the RSGM?**

557 A. Yes. Although there are uncertainties with respect to the proper application of section

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<sup>14</sup> *In the Matter of the Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2014*, Docket No. 13-035-02, Order Confirming Bench Ruling Approving Stipulation on Depreciation Rate Changes (Nov. 7, 2013).

<sup>15</sup> *Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021*, Docket No. 18-035-36, Report and Order (April 20, 2020).

558 13001(d) of the TCJA, PacifiCorp has carefully considered this matter and, based on  
559 its facts and circumstances, believes that the use of the RSGM is permitted as a  
560 normalization method of accounting.

561 **Q. Does the Internal Revenue Service (“IRS”) recognize the need for clarity with**  
562 **regard to the EDIT normalization requirements in light of the TCJA?**

563 A. Yes. In Notice 2019-33, the IRS announced its intent to issue guidance to clarify the  
564 EDIT normalization requirements, which may include guidance on the use of the  
565 RSGM; the Company anticipates this guidance will be issued in 2020. In comments  
566 submitted in response to Notice 2019-33, the Edison Electric Institute has requested  
567 that the IRS issue transitional guidance that allows taxpayers to correct potential  
568 normalization violations on a prospective basis and that the violations be forgiven  
569 without penalty. If uncertainties still exist after the guidance is issued, the Company  
570 will evaluate the need to file a private letter ruling request.

571 **VII. PENSION COSTS**

572 **Q. Please describe the status of PacifiCorp’s defined benefit pension plans.**

573 A. To reduce the risk profile of its defined benefit pension plans, PacifiCorp has, over  
574 time, shifted the accrual of new benefits to its defined contribution 401(k) plan. All  
575 non-represented employees hired after January 1, 2008, and all represented employees  
576 hired after June 30, 2013, receive retirement benefits solely through the 401(k) plan.  
577 Retirement plan benefits for represented employees are determined through the  
578 collective bargaining process through which the Company has maintained its focus on  
579 shifting to providing benefits through its 401(k) plan. The Company provided non-  
580 represented employees hired before January 1, 2008, the ability to receive their

581 retirement through either the pension plan or the 401(k) plan. This choice was offered  
582 in 2008, and 41 percent of the eligible participants migrated to the 401(k) plan. The  
583 remaining non-represented employees in the defined benefit pension plan continued to  
584 receive benefit accruals until accruals were frozen on December 31, 2016.

585 **Q. Does this case reflect costs associated with PacifiCorp's defined benefit pension**  
586 **plans?**

587 A. Yes. The Company still incurs net periodic benefit costs for its defined benefit pension  
588 plans. The Company's net periodic benefit costs generally include interest costs  
589 associated with discounting the projected benefit obligation and amortization of net  
590 unrecognized gains and losses, offset by the expected return on plan investments. The  
591 level of these projected costs is driven by various assumptions, including the interest  
592 rate used to discount the liability, life expectancy and other demographics of the  
593 Company's plan participants, and the expected long-term rate of return based on the  
594 mix of investments. This filing reflects total-Company pension costs of \$8.8 million,  
595 including a projected settlement loss of approximately \$11.9 million during the 2021  
596 test period.

597 **Q. What is a settlement loss?**

598 A. Accounting guidance provides for delayed recognition of certain gains and losses.  
599 These unrecognized costs include an accumulation of past actuarial gains and losses  
600 that result from changes in actuarial assumptions, such as the discount rate, and the  
601 difference between expected and actual experience — for example, asset returns that  
602 exceed or underperform the level assumed in determining net periodic benefit cost.  
603 Under the Financial Accounting Standards Board's Accounting Standards Codification

604 (“ASC”) 715, Compensation - Retirement Benefits<sup>16</sup> and ASC 980, Regulated  
605 Operations, the majority of the Company’s unrecognized net loss is currently amortized  
606 over approximately 21 years, which represents the average remaining life expectancy  
607 of plan participants. A settlement loss occurs when the aggregate lump sum cash  
608 distributions in a calendar year exceed a defined threshold (service cost plus interest  
609 cost), requiring under ASC 715 immediate recognition in earnings of a portion of the  
610 unrecognized actuarial gains or losses. If not for this requirement, such portion of the  
611 net actuarial loss would eventually flow through expense as part of the ongoing  
612 amortization over the approximately 21-year period.

613 **Q. Why are actuarial gains and losses an important component of on-going pension**  
614 **expense under ASC 715?**

615 A. Actuarial gains and losses arise annually as remeasurement occurs each year-end under  
616 ASC 715 due to changes in assumptions, differences between expected and actual asset  
617 returns, and actuarial experience. As of December 31, 2019, the Company had  
618 \$422 million of unrecognized net actuarial losses recorded as a regulatory asset that  
619 will generally be recognized to expense over the average remaining life of plan  
620 participants (currently approximately 21 years), making it a significant portion of the  
621 Company’s annual pension expense. Recognition of actuarial gains and losses are  
622 amortized over time rather than in the year they occur, which can help minimize  
623 volatility in expense from year to year. However, as I described above, settlement  
624 accounting under ASC 715 can trigger accelerated recognition of a portion of the  
625 unrecognized net actuarial losses. The Company last recognized a settlement loss in

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<sup>16</sup> Formerly known as “FAS 87.”

2018 on a total-Company basis of \$22 million, approximately \$9.5 million of which was Utah's share. In Docket No. 18-035-48, the Company requested approval of deferred accounting treatment related to this settlement loss. The Commission denied the Company's request, holding that the pension settlement costs were not unforeseeable or extraordinary sufficient to warrant a deferred accounting order.<sup>17</sup>

**Q. Does the Company anticipate that settlement losses under ASC 715 will be triggered during the next few years and if so, what is the driver?**

A. Yes. Recent history demonstrates that during periods of low interest rates, a higher percentage of participants elect lump sum distributions. Thus, with the very low interest rate environment present at the time the Company's projections for this filing were compiled and the knowledge of what the Company experienced in 2018 when interest rates were similarly low, the Company anticipates that additional settlement losses will occur. Based on actuarial projections, settlement losses of \$18.5 million and \$11.9 million are forecast during 2020 and 2021, respectively, justifying the inclusion of these costs in base rates. The settlement loss projections were based on market conditions in early 2020.

In periods of low interest rates, the Company experiences lower interest cost on the benefit obligation, which keeps the threshold for determining settlement accounting at a low level. Table 7 below shows the settlement threshold for the last seven years along with the projections for 2020 and 2021. The declining threshold is primarily driven by the low interest rate environment. The Company is likely to be subject to a settlement charge each year that interest rates are sufficiently low.

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<sup>17</sup> *Application of Rocky Mountain Power for an Accounting Order for Settlement Charges Related to its Pension Plans*, Docket No. 18-035-48, Order at 6-7 (May 22, 2019).

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**Table 7: Recent History and Projections of Settlement Threshold (\$ in millions)**

	2013	2014	2015	2016	2017	2018	2019	2020	Projected 2021
Service cost	\$5.9	\$5.3	\$4.7	\$4.1	0	0	0	0	0
Interest cost	\$51.9	\$54.0	\$50.6	\$51.8	\$47.3	\$41.1	\$42.6	\$34.4	\$31.9
Settlement threshold (service cost + interest cost)	\$57.8	\$59.3	\$55.3	\$55.9	\$47.3	\$41.1	\$42.6	\$34.4	\$31.9

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In addition to a low settlement threshold, the Company has made assumptions about the number of participants who will take lump sum distributions upon retirement along with their estimated payout. For purposes of valuing the pension benefit obligation, the Company's actuaries generally assume (based on historical experience) that 60 percent of participants will elect lump sum distributions. However, in performing the annual remeasurement of the pension benefit obligation at December 31, 2019, the Company's actuaries assumed 80 percent of participants would elect lump sum distributions in 2020 in anticipation of an increase in the percentage of retiring participants electing lump sums due to the unprecedentedly low interest rates. For 2021, 60 percent of participants are assumed to elect lump sum distributions. In any given year, the actual percentage of participants electing lump sum distributions will differ from what was assumed.

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Table 8 below shows the historical number of participants electing lump sum distributions and the resulting value paid out of the plan along with the projections for 2020 and 2021.

**Table 8: Historical and Projected Lump Sum Distribution Information (\$ in millions)**

	2013	2014	2015	2016	2017	2018	2019	Projected 2020	Projected 2021
Lump Sum Distributions	\$52.2	\$22.0	\$40.5	\$31.9	\$40.0	\$52.3	\$22.7	\$50.8	\$34.4
Distributions in Excess of Threshold	0	0	0	0	0	\$ 11.2	0	\$ 16.4	\$ 2.5
Discount Rate	4.05%	4.8%	4%	4.4%	4.05%	3.6%	4.25%	3.25%	3.25%
Minimum Present Value Segment Rates <sup>(1)</sup>	1.02% 3.71% 4.67%	1.40% 4.66% 5.62%	1.40% 3.98% 5.04%	1.69% 4.11% 5.07%	1.47% 3.34% 4.30%	1.96% 3.58% 4.35%	3.21% 4.26% 4.55%	2.13% 3.07% 3.65%	2.04% 3.09% 3.68%
Number of Participants Electing Lump Sums	204	150	216	224	205	211	114	231	172
Percentage of Participants Electing Lump Sums	66.3%	50.2%	64.9%	68.7%	58.4%	73.3%	67.1%	80%	60%

1. Other than for 2021, represents the IRS's published minimum present value segment rates from September of the preceding year, which are used to value lump sum distributions taken in the subsequent year, in accordance with the Company's pension plan document. For example, the 2.13%/3.07%/3.65% presented under 2020 are the September 2019 rates applicable to lump sum distributions to be taken in 2020. Rates included for 2021 are based on the November 2019 rates published by the IRS, which were the most recently available at the time the projections were compiled. The December 2019 rates were 2.03%/3.06%/3.59%.

As of December 31, 2019, interest rates decreased significantly, resulting in a 3.25 percent discount rate used to perform the annual remeasurement of the Company's benefit obligation and determine the interest cost component of the Company's net periodic benefit cost for 2020. This compares to a 4.25 percent discount rate at December 31, 2018. As presented in Table 7, this decrease results in lower interest cost and thus a lower settlement loss threshold. As presented in Table 8, the applicable minimum present value segment rates for 2020 lump sum distributions are very low; thus, the Company projects higher lump sum distributions and the triggering of a settlement loss in 2020 of an estimated \$18.5 million. Based on the current low interest rate environment, the Company projects a settlement loss of \$11.9 million in 2021



using the assumptions presented in Table 8. When similar circumstances were present in 2018, the Company incurred a settlement loss of \$22 million.

**VIII. RATE TREATMENT NET PREPAID PENSION AND OTHER POST-RETIREMENT ASSETS**

**Q. What is the Company's proposed rate treatment for its prepaid pension and other post-retirement assets, net of accumulated deferred income taxes ("net prepaid pension and other post-retirement asset" or "net prepaid")?**

A. The Company proposes inclusion of its net prepaid pension and other post-retirement asset in rate base with a return equal to the Company's weighted average cost of capital ("WACC"). Inclusion of the net prepaid in rate base would allow the Company to recover its prospective financing costs associated with the net prepaid.

**Q. Please describe how the net prepaid pension and other post-retirement asset is computed and what it represents.**

A. The prepaid pension and other post-retirement asset represents cumulative contributions made to the Company's defined benefit plans in excess of cumulative expense recognized for accounting purposes. These prepaid assets can also be computed by taking the Company's regulatory asset associated with unrecognized net periodic benefit cost for the plans less the net underfunded status of the plans. The prepaid assets are then reduced by associated accumulated deferred income tax liabilities to arrive at the Company's net prepaid pension and other post-retirement asset.

703 **Q. What balance is the Company proposing to include in rate base associated with**  
704 **its net prepaid pension and other post-retirement asset?**

705 A. The Company proposes to include \$252.335 million in rate base based on the 13-month  
706 average of its net prepaid pension and other post-retirement asset reduced for joint  
707 owner cutback for the 13-month period ended December 31, 2021. This amount reflects  
708 PacifiCorp's prepaid pension asset of \$326.557 million plus its other post-retirement  
709 prepaid asset of \$7.046 million less associated accumulated deferred income tax  
710 liabilities of \$81.268 million. This amount, along with the net prepaid pension and other  
711 post-retirement asset at December 31, 2019, is included in the exhibits to  
712 Mr. McDougal's direct testimony.

713 **Q. What is the basis for including the net prepaid pension and other post-retirement**  
714 **asset in rate base?**

715 A. Over the life of a plan, cumulative contributions and expense will be equal. However,  
716 at any point during the life of a plan, cumulative contributions and expense will differ.  
717 The prepaid concept arises from cumulative contributions to the plans exceeding  
718 cumulative pension and other post-retirement expense (also referred to as net periodic  
719 benefit cost). While the Company recovers its net periodic benefit cost through cost of  
720 service, the Company finances any difference between the amounts cumulatively  
721 contributed to the plans and the amounts cumulatively recognized as expense for  
722 accounting purposes with its blended capital. Thus, inclusion of the net prepaid pension  
723 and other post-retirement asset in rate base earning a return at the Company's  
724 authorized WACC would allow the Company to recover this financing cost.

725 **Q. What factors contribute to contributions differing from net periodic benefit cost?**

726 A. Contributions to the pension plans are generally driven by funding requirements under  
727 the Employee Retirement Income Security Act of 1974 (“ERISA”), which encompass  
728 the funding requirements of the federal Pension Protection Act of 2006. Ensuring  
729 minimums under these requirements are met mitigates impairing the tax exempt status  
730 of the plans and avoids triggering of benefit restrictions. Other factors, such as Internal  
731 Revenue Service funding limits and deductibility rules, influence the level of  
732 contributions to other post-retirement plans.

733 Net periodic benefit cost is computed in accordance with generally accepted  
734 accounting principles under ACS 715. Thus, at any point in time during the life of the  
735 plans, contributions will differ from the amounts recognized as net periodic benefit cost  
736 for accounting purposes. As noted, however, over the life of the plans, contributions  
737 and expense will be equal.

738 **Q. What is the current and historical rate treatment of pension and other post-**  
739 **retirement net periodic benefit cost?**

740 A. The Company currently recovers its net periodic benefit cost under ASC 715 by  
741 including the amount for the applicable test period in determining revenue requirement  
742 in its general rate case filings. No balancing account is utilized for pension and other  
743 post-retirement costs. Prior to the adoption of Financial Accounting Standards Board  
744 Statement No. 87 (“FAS 87”) in 1987, the Company recovered pension costs based on  
745 contributions. At the time of adoption, the Company began recovering pension costs  
746 based on net periodic benefit cost under FAS 87 (later codified as ASC 715) with the  
747 cumulative difference between the two methods recovered over a five-year period.

748 Thus, the Company has effectively recovered pension costs over time on the basis of  
749 Generally Accepted Accounting Principles (“GAAP”) expense leaving it to bear the  
750 costs to finance contributions in excess of expense. Prior to the adoption of the  
751 Financial Accounting Standards Board’s Statement No. 106 (also later codified as ASC  
752 715), other post-retirement costs were expensed and recovered on a pay-as-you-go  
753 basis. Upon adoption of the new guidance, recovery continued to be based on the  
754 Company’s expense. Thus for other post-retirement costs, recovery has also been  
755 aligned to expense over time leaving the Company to finance any differences between  
756 contributions and expense.

757 **Q. To the extent the net prepaid is in an accrued position, would inclusion in rate base**  
758 **continue to be appropriate?**

759 A. Yes. As with any other rate base item where the difference between timing of cash  
760 payments and expense recognition differ, the item should be included in rate base  
761 whether in an asset or liability position. To the extent cumulative expense exceeds  
762 cumulative Company contributions to the plans, it would be appropriate to reduce rate  
763 base for the resulting net accrued position in order to pass the benefit to customers for  
764 having provided recovery of the expense in excess of cash outlays by the Company.

765 **Q. Please clarify why the cumulative net prepaid should be included in rate base**  
766 **rather than only prospective differences between expense and contributions?**

767 A. The cumulative difference between expense and contributions to date must be included  
768 in rate base in order to avoid skewed outcomes that would arise if only prospective  
769 differences between expense and contributions were to be included. For example, in a  
770 year where contributions to the plans are \$0 and expense is \$10, a net accrued position

771 of \$10 would result on a pre-tax basis. If only this new activity is included in rate base  
772 despite a historical net prepaid balance, customers would benefit from a rate base  
773 reduction while the Company would continue to incur financing costs on the historical  
774 difference between cumulative contributions and expense. Including the cumulative net  
775 prepaid in rate base today with a return based on the Company's WACC provides it the  
776 ability to recover only prospective financing costs associated with the net prepaid.

777 **Q. How does negative expense impact the net prepaid pension and other post-**  
778 **retirement asset?**

779 A. Negative net periodic benefit cost increases the net prepaid but remains appropriate to  
780 include in rate base. Since the Company recovers pension and other post-retirement  
781 benefits cost through cost of service, negative expense flows through to customers  
782 resulting in a lower cash position for the Company. The Company incurs financing  
783 costs on the difference between cumulative contributions and cumulative net periodic  
784 benefit cost regardless of whether that cost is positive or negative.

785 **Q. Does historical capitalization of pension and other post-retirement cost impact the**  
786 **Company's proposal to include the associated net prepaid in rate base?**

787 A. No. While the capitalized portion of net periodic benefit cost is included in rate base  
788 through in-service plant, there is no doubling up of rate base for this component. This  
789 is because the Company's net prepaid reflects the difference between cash  
790 contributions and expense under ASC 715 prior to capitalization as if that difference  
791 truly represented the Company's excess cash outlays. However, the Company only  
792 recovers the portion capitalized to in-service plant as the cost is depreciated over the  
793 plant's life. Thus, the combined inclusion in rate base of the capitalized portion of net

794 periodic benefit cost through in-service plant and the net prepaid pension and other  
795 post-retirement asset would allow the Company to be made whole on its costs to  
796 finance the contributions in excess of expense recognized and recovered in rates.

797 **Q. Does the fact that actual pension and other post-retirement benefit cost differed**  
798 **from that included in rates impact the appropriateness of the Company's**  
799 **proposal?**

800 A. No. As with any other rate base item where no balancing account exists (e.g.,  
801 investment in in-service plant, coal inventory), no adjustments are made for changes in  
802 the balances between general rate cases.

803 **Q. Why is the Company's WACC the appropriate rate to apply to the net prepaid**  
804 **pension and other post-retirement asset?**

805 A. The Company's blended capital structure of long-term debt and equity financing is the  
806 source of financing for the net prepaid just as it is for other rate base items such as  
807 investment in in-service plant. Thus, to provide a return at something less than the  
808 Company's WACC would result in the Company not recovering its costs to finance the  
809 difference between its cash outlays and the amounts charged to expense and recovered  
810 from customers.

811 **Q. Does inclusion of the net prepaid in rate base shift additional risk to customers?**

812 A. No. While much volatility exists with defined benefit plans due to asset returns that are  
813 impacted by market conditions and changes in underlying assumptions, such as the  
814 discount rate, these risks are encompassed in net periodic benefit cost and balanced  
815 with smoothing methods allowed under ASC 715. Including the net prepaid in rate base  
816 does not change these risks or who bears them. Inclusion of the net prepaid in rate base

817 simply provides the Company the opportunity to recover its underlying financing costs  
818 associated with the plans.

819 **VIII. CONCLUSION**

820 **Q. Please summarize your recommendations to the Commission.**

821 A. I respectfully request the Commission adopt PacifiCorp's proposed capital structure  
822 with a common equity level of 53.67 percent. This capital structure balances the  
823 financial integrity of the Company and costs to customers by reflecting the minimum  
824 equity ratio necessary for PacifiCorp to maintain its ratings under current market  
825 conditions, especially given the passage of the TCJA. When combined with  
826 PacifiCorp's updated cost of long-term debt of 4.81 percent and the cost of equity of  
827 10.20 percent recommended by Ms. Bulkley, this produces a reasonable overall cost of  
828 capital of 7.70 percent.

829 In addition, the Company recommends that the Commission acknowledge the  
830 reasonableness of PacifiCorp's treatment of its TCJA tax benefits in rates, and approve  
831 PacifiCorp's projected pension costs and prepaid pension balance included in this case.

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

833 A. Yes.

Rocky Mountain Power  
Exhibit RMP\_\_\_(NLK-1)  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

---

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Pro forma Cost of Long-term Debt

May 2020



**PACIFICORP**

# Electric Operations

## Pro forma Ave Cost of Long-Term Debt Summary

12 months ended December 31, 2021

[illegible]

Rocky Mountain Power  
Exhibit RMP\_\_\_\_(NLK-1) 1 of 3  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

## PACIFICORP

## Electric Operations

## Pro forma Ave Cost of Long-Term Debt Summary

12 months ended December 31, 2021

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT		ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY		MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
						ORIGINAL	SOE AVE OUTSTANDING			TOTAL DOLLAR AMOUNT	PER \$100 PRINCIPAL AMOUNT			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1														1
2														2
3	3.850%	Series due Jun 2021	05/12/11	06/15/21	10	\$400,000,000	\$160,000,000	(\$1,500,455)	\$0	\$138,499,545	\$99,062	3.963%	\$6,340,800	3
4	2.950%	Series due Feb 2022	01/06/12	02/01/22	10	\$350,000,000	\$350,000,000	(\$2,732,350)	\$0	\$347,267,650	\$99,219	3.040%	\$10,640,000	4
5	2.950%	Series due Feb 2022 (2)	03/06/12	02/01/22	10	\$100,000,000	\$100,000,000	(\$173,129)	(\$4,970,793)	\$94,836,079	\$94,856	3.571%	\$3,571,000	5
6	2.950%	Series due Jun 2023	06/06/13	06/01/23	10	\$300,000,000	\$300,000,000	(\$2,759,352)	\$0	\$297,240,648	\$99,080	3.058%	\$9,174,000	6
7	3.600%	Series due Apr 2024	03/13/14	04/01/24	10	\$425,000,000	\$425,000,000	(\$3,600,164)	(\$1,943,075)	\$419,456,761	\$98,696	3.757%	\$15,967,250	7
8	3.350%	Series due Jul 2025	06/19/15	07/01/25	10	\$250,000,000	\$250,000,000	(\$2,441,421)	\$0	\$247,558,579	\$99,023	3.466%	\$8,665,000	8
9	3.500%	Series due Jun 2029	03/01/19	06/15/29	10	\$400,000,000	\$400,000,000	(\$2,874,181)	\$0	\$397,125,819	\$99,281	3.584%	\$14,336,000	9
10	2.700%	Series due Sep 2030	04/08/20	09/15/30	10	\$400,000,000	\$400,000,000	(\$2,880,000)	\$0	\$397,120,000	\$99,280	2.780%	\$11,120,000	10
11	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	\$300,000,000	\$300,000,000	(\$3,701,310)	\$0	\$296,298,690	\$98,766	7.807%	\$23,421,000	11
12	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	\$200,000,000	\$200,000,000	(\$2,614,365)	\$0	\$197,385,635	\$98,693	5.994%	\$11,988,000	12
13	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	\$300,000,000	\$300,000,000	(\$3,992,021)	(\$1,295,995)	\$294,711,984	\$98,237	5.369%	\$16,107,500	13
14	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	\$350,000,000	\$350,000,000	(\$4,048,881)	\$0	\$345,951,119	\$98,843	6.185%	\$21,647,500	14
15	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	\$600,000,000	\$600,000,000	(\$613,216)	\$0	\$599,386,784	\$99,898	5.757%	\$34,542,000	15
16	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	\$600,000,000	\$600,000,000	(\$5,877,281)	\$0	\$594,122,719	\$99,020	6.323%	\$37,938,000	16
17	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	\$300,000,000	\$300,000,000	(\$3,961,333)	\$0	\$296,038,667	\$98,680	6.450%	\$19,350,000	17
18	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	\$650,000,000	\$650,000,000	(\$12,309,687)	\$0	\$637,690,313	\$98,106	6.139%	\$39,903,500	18
19	4.100%	Series due Feb 2042	01/06/12	02/01/42	30	\$300,000,000	\$300,000,000	(\$3,724,911)	\$0	\$296,275,089	\$98,758	4.173%	\$12,519,000	19
20	4.125%	Series due Jan 2049	07/13/18	01/15/49	31	\$600,000,000	\$600,000,000	(\$6,984,085)	\$0	\$593,015,915	\$98,836	4.193%	\$25,158,000	20
21	4.150%	Series due Feb 2050	03/01/19	02/15/50	31	\$600,000,000	\$600,000,000	(\$7,938,771)	\$0	\$592,061,229	\$98,677	4.227%	\$25,362,000	21
22	3.300%	Series due Mar 2051	04/08/20	03/15/51	31	\$600,000,000	\$600,000,000	(\$10,134,000)	\$0	\$589,866,000	\$98,311	3.388%	\$20,328,000	22
23	4.631%	Subtotal - Buller FMBs			24		\$7,785,000,000	(\$84,860,911)	(\$8,209,863)	\$7,691,929,226		4.728%	\$368,078,050	23
24														24
25	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	\$15,000,000	\$12,000,000	(\$92,161)	(\$1,643,137)	\$10,264,702	\$85,539	10.066%	\$1,207,920	25
26	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	\$5,000,000	\$4,000,000	(\$30,720)	(\$547,712)	\$3,421,567	\$85,539	9.889%	\$395,560	26
27	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	\$5,000,000	\$5,000,000	(\$33,243)	(\$684,641)	\$4,282,117	\$85,642	9.745%	\$487,250	27
28	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	\$4,000,000	\$4,000,000	(\$30,594)	(\$547,712)	\$3,421,693	\$85,542	9.768%	\$390,720	28
29	2.975%	Subtotal - Series C MTNs			11		\$25,000,000	(\$186,718)	(\$3,423,203)	\$21,390,079		9.926%	\$2,481,450	29
30														30
31	8.050%	Series E due Sep 2022	09/18/92	09/01/22	30	\$15,000,000	\$15,000,000	(\$131,471)	(\$1,695,566)	\$13,172,963	\$87,820	9.257%	\$1,388,550	31
32	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	\$8,000,000	\$8,000,000	(\$70,118)	(\$904,302)	\$7,025,580	\$87,820	9.280%	\$742,400	32
33	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	\$12,000,000	\$12,000,000	(\$105,177)	(\$1,356,453)	\$10,538,370	\$87,820	9.325%	\$1,119,000	33
34	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	\$50,000,000	\$50,000,000	(\$438,238)	(\$5,651,887)	\$43,909,875	\$87,820	9.336%	\$4,668,000	34
35	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	\$10,000,000	\$10,000,000	(\$87,648)	(\$1,130,377)	\$8,781,975	\$87,820	9.258%	\$925,800	35
36	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	\$25,000,000	\$25,000,000	(\$200,190)	(\$2,061,627)	\$22,738,182	\$90,953	8.953%	\$2,238,250	36
37	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	\$26,000,000	\$26,000,000	(\$208,198)	(\$2,938,981)	\$22,852,821	\$87,895	9.283%	\$2,413,580	37
38	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	\$4,000,000	\$4,000,000	\$51,229	(\$88,989)	\$3,962,241	\$99,056	8.316%	\$332,640	38
39	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	\$5,000,000	\$5,000,000	(\$37,914)	(\$335,843)	\$4,626,243	\$92,525	8.951%	\$447,550	39
40	8.099%	Subtotal - Series E MTNs			30		\$155,000,000	(\$1,227,725)	(\$16,164,025)	\$137,608,250		9.210%	\$14,275,770	40
41														41
42	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	\$11,000,000	\$11,000,000	(\$100,622)	(\$89,062)	\$10,310,316	\$93,730	7.804%	\$858,440	42
43	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	\$27,000,000	\$27,000,000	(\$246,981)	(\$1,445,880)	\$25,307,139	\$93,730	7.804%	\$2,107,080	43
44	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	\$15,000,000	\$15,000,000	(\$137,211)	(\$268,624)	\$14,594,165	\$97,294	7.457%	\$1,118,550	44
45	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	\$30,000,000	\$30,000,000	(\$274,423)	(\$537,248)	\$29,188,329	\$97,294	7.467%	\$2,240,100	45
46	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	\$2,000,000	\$2,000,000	(\$15,300)	\$0	\$1,984,700	\$99,235	6.810%	\$136,200	46
47	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	\$2,000,000	\$2,000,000	(\$15,300)	\$0	\$1,984,700	\$99,235	6.780%	\$135,600	47
48	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	\$5,000,000	\$5,000,000	(\$38,250)	(\$34,169)	\$4,927,581	\$98,552	6.865%	\$343,250	48
49	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	\$12,000,000	\$12,000,000	(\$91,396)	\$0	\$11,908,604	\$99,238	6.810%	\$817,200	49
50	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	\$16,000,000	\$16,000,000	(\$121,861)	\$0	\$15,878,139	\$99,238	6.810%	\$1,089,600	50
51	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	\$20,000,000	\$20,000,000	(\$152,326)	\$0	\$19,847,674	\$99,238	6.810%	\$1,362,000	51
52	7.044%	Subtotal - Series F MTNs			30		\$140,000,000	(\$1,193,670)	(\$2,874,983)	\$135,931,347		7.291%	\$10,208,020	52

[illegible]

Rocky Mountain Power  
Exhibit RMP\_\_\_(NLK-2)  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Arizona Public Service Co Letter to Commission

May 2020

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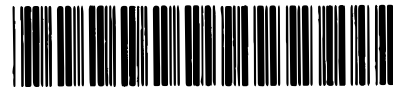
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ARIZONA CORPORATION COMMISSION  
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LAW DEPARTMENT



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Rocky Mountain Power  
Exhibit RMP (NLK-2) 1 of 11  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

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October 17, 2008

Arizona Corporation Commission  
DOCKETED

OCT 17 2008

Commissioner Kristin K. Mayes  
Arizona Corporation Commission  
1200 West Washington  
Phoenix, Arizona 85007



Re: Docket No. E-01345A-08-0172 (Interim Rate Motion)

Dear Commissioner Mayes:

On October 8, 2008, you filed a letter in which you requested Arizona Public Service Company ("APS" or "Company") to respond to five specific issues covering a range of subjects. Because several of these issues are germane to the Company's pending Motion for Interim Rates, the Company has chosen to submit its response in the above docket. For the convenience of the parties to this proceeding, I have attached a copy of your October 8<sup>th</sup> letter as Appendix A.

**APS Access to Commercial Paper Market and Other Credit-Related Issues**

APS first began experiencing trouble accessing the commercial paper market in August of 2007 when the sub-prime credit issues began to impact the capital markets. Access has continued to be sporadic throughout 2008, with the amount of commercial paper APS can issue often being limited even when access to the market was possible. Beginning September 17, 2008, the commercial paper market has been completely closed to APS.

As discussed during the hearing, APS had total lines of credit of \$900 million. The first line of \$400 million expires at the end of 2010, with a second for \$500 million expiring at the end of 2011. The purpose of these lines of credit is to provide the Company with liquidity and working capital when commercial paper cannot be utilized – not fund capital expenditures.<sup>1</sup> Indeed, Decision No. 69947 (October 30, 2007) specifically limited the use of the \$500 million line of credit to fuel/purchased power requirements and thus cannot be used to fund the Company's capital requirements. As of September 30, 2008, approximately \$270 million had to be drawn down due to the problems in the commercial paper market described above. Also, \$34 million of the Company's credit line was with bankrupt Lehman Brothers and thus no longer

<sup>1</sup> Borrowing on bank lines of credit is normally 25 to 50 basis points more expensive than commercial paper.

APS • APS Energy Services • SunCor • El Dorado •

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exists. Another \$36 million was with Wachovia, which is in the process of being acquired by Wells Fargo. Whether the new owner of Wachovia will assume the \$36 million commitment is uncertain, to say the least. Accordingly, APS's previous \$900 million lines of credit are now no more than \$866 million, and may be as low as \$830 million. Finally, as a result of recent write-downs of bank assets, there is \$2 trillion less credit capacity in the U.S. banking system than there was before this global financial crisis began. As a result, APS will likely encounter difficulty in maintaining its remaining lines of credit in the future, and there is no doubt that these lines of credit would, in any case, be insufficient to meet APS's capital expenditure needs over the next few years.

Liquidity is absolutely vital to the financial integrity of an electric utility. APS itself was contacted by each of the three rating agencies after the Lehman Brothers bankruptcy and asked about the Company's exposure to Lehman, Morgan Stanley, Merrill Lynch and Goldman Sachs, as well as its ability to count on its lines of credit given the chaos in the short-term credit markets. A recent example of the critical importance of liquidity is Constellation Energy, the parent of Baltimore Gas & Electric Company, which began 2008 with a stock price of over \$100 per share. After facing a liquidity crisis driven by threatened credit rating downgrades and the resultant cash collateral calls that nearly drove Constellation to the brink of bankruptcy, it was forced to sell itself to MidAmerican Energy (the same entity that bought out PacifiCorp) for \$26.50 per share.

And the damage has not been limited to the short-term debt market. Despite massive efforts by our Federal government and governments in Europe and Asia to pump liquidity into the national and international credit markets, access to the corporate debt market is extremely strained, with only the most highly-rated corporations being successful in raising long-term debt capital. At present, APS likely could not successfully issue long-term debt. Whether this financial market environment will improve by the spring of next year, when APS likely will need to issue debt, is unknown.

### **GeoSmart Solar Financing Program**

On Thursday, September 25, 2008 GE Money announced that it will no longer offer unsecured installment consumer financing for its energy efficiency and renewable energy programs after October 23, 2008 because of the current turmoil in the credit markets. The action specifically affected the Electric & Gas Industries Association's ("EGIA") *GEOSmart* Financing Program offered by APS because GE Money provided the financial support for the program. Although APS had no prior warning of GE Money's actions, APS remains committed to its partnership with EGIA. EGIA, as a non-profit entity implementing similar financing programs for utilities around the country, is situated to identify other suitable financial institutions to back the *GeoSmart* program. In recent conversations, EGIA informed APS that a number of financial institutions have been identified that **may** be able to provide funding for *GEOSmart*. APS remains hopeful but cannot offer any assurance that EGIA will secure other financial backing in the future.

### **Transactions with Investment Banks or Similar Financial Institutions**

Attached as Appendix B is a list of the banks with which APS has existing lines of credit. As noted before, Lehman Brothers and Wachovia are in that group. APS has also submitted a \$1.1 million claim against Lehman Brothers in bankruptcy over a hedging transaction. APS has conducted numerous transactions with Morgan Stanley and Goldman Sachs, who together are major players in the U.S energy markets. Although it would seriously reduce the overall liquidity of these energy markets should Morgan Stanley and/or Goldman Sachs bow out of the energy market, APS itself had controls in place well before all these problems began that limited its exposure to any single trading partner, including those discussed above. However, with chaotic and unprecedented market events such as we are presently experiencing, no amount of internal controls can provide complete protection against potential losses.<sup>2</sup> Finally, AIG is a carrier for APS property and casualty insurance. APS believes that these insurance policies will continue to be honored.

### **Auction Rate Securities**

APS does not have any funds invested in auction rate securities ("ARS"). APS is an issuer of ARS, with \$343 million outstanding and with maturities in 2029 and 2034. The average rate of interest paid on these securities has been 3.2%, thus providing very attractive financing for APS and its customers.

### **Palo Verde**

Palo Verde Unit 3 experienced two relatively brief unplanned outages recently. The first was from September 16 to September 20 when a failed transmitter in the control circuitry for one of the two power supplies to the reactor control rods required the unit to be shut down. That was safely accomplished, and after the electronic card that included the failed component was replaced, the unit was returned to full power without incident. The second was from September 27 to 30 when high sulfate levels were detected in the secondary steam system (the system that connects the steam generators with the steam turbine). After operators had shut down the unit, the secondary system chemistry was returned to normal, the unit again returned to service without incident and has been operating at full power since then. APS estimates that the amount of additional fuel and purchased power costs deferred for recovery through the PSA to be approximately \$3 million.<sup>3</sup>

Neither outage involved what could be characterized as an unusual event for a nuclear power plant and is the sort of occurrence anticipated in the budgeted effective forced outage rate ("EFOR") for Palo Verde. Palo Verde, like all generators, including all APS generators, has an

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<sup>2</sup> Although such transactions are not directly with APS, the APS decommissioning trusts and the Pinnacle West retirement funds have relatively small investments in some of the troubled entities identified in your letter, as likely do most if not all large investment funds in this country.

<sup>3</sup> As the Commission is aware, APS absorbs 10% of higher fuel costs, and a portion of outage costs are embedded in the base fuel cost. In addition, a small amount is allocated to wholesale customers. Thus, the total cost of the outages was \$4.4 million.

anticipated EFOR based primarily on past operations. This is merely an acknowledgement that all machines, no matter how well designed, constructed, operated, and maintained, will sometimes fail. Electric generators are no exception to that rule.

To date this year, the overall Palo Verde capacity factor has been 98% (excluding refueling outages). This past summer, Palo Verde set an all-time record for generation.

Throughout both outage events, Palo Verde staff demonstrated their safety-first focus by using effective problem identification and resolution behaviors, took proper action during troubleshooting (including developing contingency plans) and work planning. They executed all needed repairs with a focus on human performance. The NRC was kept fully informed throughout these outages and monitored Palo Verde's decision-making process and the actions taken. APS does not believe these outages have had any negative impact on APS's substantial progress in resolving the NRC's Confirmatory Action Letter.

Sincerely,



Thomas L. Mumaw

Attorney for Arizona Public  
Service Company

Attachments

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William A. Mundell  
Jeff Hatch-Miller  
Gary Pierce  
Brian McNeil  
Ernest Johnson  
Lyn A. Farmer  
Janet Wagner  
Rebecca Wilder  
Janice Alward  
Parties of Record  
Docket Control



Copies of the foregoing emailed or mailed  
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Rocky Mountain Power  
Tina Gamble Exhibit RMP (NLK-2) 5 of 11  
RUCO Docket No. 20-035-04  
Witness: Nikki L. Kobliha  
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Rocky Mountain Power  
Exhibit RMP (NLK-2) 6 of 11  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha  
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# Appendix A

**COMMISSIONERS**  
MIKE GLEASON - Chairman  
WILLIAM A. MUNDELL  
JEFF HATCH-MILLER  
KRISTIN K. MAYES  
GARY PIERCE



**ARIZONA CORPORATION COMMISSION**

Rocky Mountain Power  
Exhibit RM (PL 12) of 11  
KRISTIN K. MAYES  
Commissioner  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha  
Direct Line: (602) 542-4143  
Fax: (602) 542-0765  
E-mail: kmayes@azcc.gov

October 8, 2008

Mr. Don Brandt  
President and CEO  
Arizona Public Service  
400 No. Fifth Street  
M.S. 9042  
Phoenix, AZ 85004

**Re: Impact of recent financial crisis on APS' access to commercial paper markets and ability to finance capital projects; forced cancellation of GeoSmart Solar Loan Program; transactions with investment banks; exposure to auction rate securities; status of outages at Palo Verde Nuclear Generating Station's Unit 3.**

Dear Mr. Brandt:

As you know, the recent upheaval in America's financial markets has had an unsettling effect on our national and local economies. It has also had serious consequences for individuals and companies who need to access financing, as credit tightens and capital markets become less fluid.

In recognition of the current environment, I write to request that you provide the Commission with information regarding whether the unfolding events on Wall Street have had an impact on Arizona Public Service Company ("APS"), with a particular focus on several areas.

First, please tell the Commission whether APS has experienced difficulty gaining access to short or long term debt markets. In particular, have you seen a decline in the Company's ability to issue commercial paper, a practice that has become common among large utilities seeking to make payments for short term capital expenditures and operating expenses. If so, please describe the ways in which you have responded to this deficiency in order to meet the Company's capital needs. Have you experienced additional expenses associated with accessing these markets? What is the short-term and long-term impact to APS' planned capital projects?

Second, APS recently reported to my office that it was forced to scuttle its GeoSmart Solar Financing Program – the program by which APS was offering loans to customers wishing to install solar panels who could not afford to do so solely using rebates – because General Electric pulled its funding due to the credit crisis. Please detail the circumstances surrounding this program suspension and whether you believe APS will be able to re-start the program in the future. Please also inform the Commission whether any other renewable energy or other capital expenditure programs have been threatened or come under pressure as a result of the tightened credit markets, and the Company's strategy for addressing these pressures.

Page 2

Rocky Mountain Power  
Exhibit RMP\_\_\_(NLK-2) 9 of 11  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

Third, please tell the Commission whether APS engaged in any significant financial transactions with Lehman Brothers, American International Group, Bear Stearns, or any other investment firm that has been the subject of recent bankruptcies or governmental takeovers. If so, please detail those transactions, and to what extent they have impacted the Company.

Fourth, it is my understanding that APS has had some exposure to auction rate securities. As you know, the auction rate securities market recently collapsed. Please describe the Company's auction rate securities holdings, what worth those securities now have, and what the Company intends to do with those securities in order to minimize any losses associated with them.

Finally, as you know, Palo Verde Nuclear Generating Station's ("PVNGS") Unit Three was down from September 27<sup>th</sup> to October 1<sup>st</sup> – making for a second outage in less than a month. Please tell the Commission how these Unit Three outages will impact the Company's efforts to resolve PVNGS' Category Four status with the Nuclear Regulatory Commission, as well as the estimated replacement costs that have been passed through the Company's Purchased Power and Fuel Adjustment Clause as a result of these outages.

Thank you for your attention to these questions.

Sincerely,



Kris Mayes  
Commissioner

Cc: Chairman Mike Gleason  
Commissioner William A. Mundell  
Commissioner Jeff Hatch-Miller  
Commissioner Gary Pierce  
Ernest Johnson  
Janice Alward  
Brian McNeil  
Rebecca Wilder

# Appendix B

**APS Revolving Lines of Credit  
 (\$K)**

	<b>Bank</b>	<b>Amount</b>	<b>% of Total</b>
1	Bank of America	\$92,857	10.3%
2	Bank of New York Mellon	80,000	8.9%
3	Citigroup	76,572	8.5%
4	JPMorgan	76,572	8.5%
5	Keybank	68,571	7.6%
6	CSFB	60,857	6.7%
7	Barclays Bank	52,857	5.9%
8	Wells Fargo	52,857	5.9%
9	UBS Warburg	52,857	5.9%
10	Union Bank	38,571	4.3%
11	Sun Trust	36,000	4.0%
12	Mizuho	28,571	3.2%
13	KBC Bank	24,000	2.7%
14	Dresdner	24,000	2.7%
15	US Bank	17,143	1.9%
16	Chang Hwa Commercial Bk	15,000	1.6%
17	BOTM	11,429	1.3%
18	Northern Trust	11,429	1.3%
19	Bank Hapoalim	10,000	1.1%
20	Subtotal	\$830,143	92.3%
21	Wachovia	36,000	4.0%
22	Lehman Brothers	33,857	3.7%
23	Total	\$900,000	100.0%

Rocky Mountain Power  
Exhibit RMP\_\_\_(NLK-3)  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

New Debt Issue Spreads

May 2020



**PACIFICORP**

(1) Issuance Expenses include issuance yield discounts

**REDACTED**

Rocky Mountain Power  
Exhibit RMP\_\_\_\_(NLK-4)  
Docket No. 20-035-04  
Witness: Nikki L. Kobilha

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Redacted Exhibit Accompanying Direct Testimony of Nikki L. Kobilha

Credit Factors Utility Industry

May 2020

**THIS ATTACHMENT IS CONFIDENTIAL IN ITS  
ENTIRETY AND IS PROVIDED UNDER SEPARATE  
COVER**

Rocky Mountain Power  
Exhibit RMP\_\_\_(NLK-5)  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

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BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Variable PCBR Rates

May 2020

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2021**

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2021**

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08	2.47%	2.77%	112%
Jul-08	2.46%	4.12%	168%
Aug-08	2.47%	3.03%	123%
Sep-08	2.94%	4.57%	155%
Oct-08	3.87%	4.89%	126%
Nov-08	1.68%	2.34%	139%
Dec-08	1.01%	1.02%	101%
Jan-09	0.39%	0.70%	181%
Feb-09	0.46%	0.68%	147%
Mar-09	0.53%	0.66%	124%
Apr-09	0.45%	0.63%	140%
May-09	0.35%	0.53%	153%
Jun-09	0.32%	0.45%	143%
Jul-09	0.29%	0.41%	142%
Aug-09	0.27%	0.43%	158%
Sep-09	0.25%	0.40%	161%
Oct-09	0.24%	0.39%	159%
Nov-09	0.24%	0.37%	157%
Dec-09	0.23%	0.38%	165%
Jan-10	0.23%	0.32%	138%
Feb-10	0.23%	0.32%	137%
Mar-10	0.24%	0.32%	135%
Apr-10	0.26%	0.35%	134%
May-10	0.33%	0.34%	101%
Jun-10	0.35%	0.33%	93%
Jul-10	0.33%	0.30%	90%
Aug-10	0.27%	0.31%	115%
Sep-10	0.26%	0.31%	119%
Oct-10	0.26%	0.27%	106%
Nov-10	0.25%	0.27%	107%
Dec-10	0.26%	0.29%	110%
Jan-11	0.26%	0.26%	100%
Feb-11	0.26%	0.26%	98%

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2021**

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Mar-11	0.25%	0.24%	96%
Apr-11	0.22%	0.24%	106%
May-11	0.20%	0.20%	100%
Jun-11	0.19%	0.12%	62%
Jul-11	0.19%	0.07%	38%
Aug-11	0.21%	0.18%	83%
Sep-11	0.23%	0.18%	78%
Oct-11	0.24%	0.17%	69%
Nov-11	0.25%	0.18%	70%
Dec-11	0.28%	0.18%	62%
Jan-12	0.28%	0.18%	64%
Feb-12	0.25%	0.22%	86%
Mar-12	0.24%	0.20%	84%
Apr-12	0.24%	0.25%	104%
May-12	0.24%	0.22%	90%
Jun-12	0.24%	0.19%	78%
Jul-12	0.25%	0.17%	68%
Aug-12	0.24%	0.16%	68%
Sep-12	0.22%	0.18%	81%
Oct-12	0.21%	0.20%	93%
Nov-12	0.21%	0.20%	95%
Dec-12	0.21%	0.15%	71%
Jan-13	0.21%	0.10%	51%
Feb-13	0.20%	0.13%	63%
Mar-13	0.20%	0.13%	66%
Apr-13	0.20%	0.18%	92%
May-13	0.20%	0.18%	90%
Jun-13	0.19%	0.11%	57%
Jul-13	0.19%	0.08%	43%
Aug-13	0.18%	0.09%	47%
Sep-13	0.18%	0.09%	49%
Oct-13	0.17%	0.10%	61%
Nov-13	0.17%	0.13%	78%
Dec-13	0.17%	0.14%	82%
Jan-14	0.16%	0.12%	74%
Feb-14	0.16%	0.11%	74%
Mar-14	0.15%	0.11%	73%
Apr-14	0.15%	0.13%	87%
May-14	0.15%	0.12%	80%
Jun-14	0.15%	0.10%	67%
Jul-14	0.15%	0.09%	61%
Aug-14	0.16%	0.09%	61%
Sep-14	0.15%	0.09%	55%
Oct-14	0.15%	0.08%	55%
Nov-14	0.15%	0.09%	59%
Dec-14	0.16%	0.08%	50%
Jan-15	0.17%	0.06%	38%
Feb-15	0.17%	0.06%	36%
Mar-15	0.18%	0.06%	35%
Apr-15	0.18%	0.09%	50%
May-15	0.18%	0.15%	79%
Jun-15	0.19%	0.13%	69%
Jul-15	0.19%	0.10%	55%
Aug-15	0.20%	0.09%	46%
Sep-15	0.20%	0.09%	47%
Oct-15	0.19%	0.10%	50%
Nov-15	0.21%	0.09%	45%
Dec-15	0.35%	0.08%	24%
Jan-16	0.43%	0.09%	20%
Feb-16	0.43%	0.08%	20%
Mar-16	0.44%	0.19%	45%
Apr-16	0.44%	0.41%	94%
May-16	0.44%	0.41%	93%
Jun-16	0.45%	0.43%	95%
Jul-16	0.48%	0.43%	89%
Aug-16	0.51%	0.49%	96%
Sep-16	0.53%	0.71%	134%

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2021**

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Oct-16	0.53%	0.77%	146%
Nov-16	0.56%	0.58%	103%
Dec-16	0.71%	0.66%	93%
Jan-17	0.77%	0.69%	89%
Feb-17	0.78%	0.66%	84%
Mar-17	0.93%	0.71%	77%
Apr-17	0.99%	0.90%	91%
May-17	1.01%	0.82%	81%
Jun-17	1.17%	0.83%	71%
Jul-17	1.23%	0.85%	69%
Aug-17	1.23%	0.79%	65%
Sep-17	1.23%	0.87%	71%
Oct-17	1.24%	0.93%	75%
Nov-17	1.29%	0.96%	75%
Dec-17	1.49%	1.25%	84%
Jan-18	1.56%	1.35%	86%
Feb-18	1.60%	1.10%	69%
Mar-18	1.80%	1.32%	73%
Apr-18	1.90%	1.75%	92%
May-18	1.95%	1.46%	75%
Jun-18	2.07%	1.33%	64%
Jul-18	2.08%	1.10%	53%
Aug-18	2.07%	1.53%	74%
Sep-18	2.18%	1.56%	72%
Oct-18	2.29%	1.60%	70%
Nov-18	2.32%	1.69%	73%
Dec-18	2.45%	1.70%	69%
Jan-19	2.51%	1.43%	57%
Feb-19	2.49%	1.64%	66%
Mar-19	2.49%	1.67%	67%
Apr-19	2.48%	1.90%	77%
May-19	2.44%	1.72%	70%
Jun-19	2.40%	1.79%	74%
Jul-19	2.31%	1.45%	63%
Aug-19	2.17%	1.45%	67%
Sep-19	2.04%	1.48%	72%
Oct-19	1.88%	1.41%	75%
Nov-19	1.74%	1.18%	68%
Dec-19	1.75%	1.34%	77%
Average			84%

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
12/31/20	1.38%	84%	1.157%
3/31/21	1.34%	84%	1.128%
6/30/21	1.34%	84%	1.128%
9/30/21	1.34%	84%	1.128%
12/31/21	1.34%	84%	1.128%
5QE Ave			1.134%

\* Source: Bloomberg L.P. (2/04/20)



Rocky Mountain Power  
Exhibit RMP\_\_\_(NLK-6)  
Docket No. 20-035-04  
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Cost of Preferred Stock

May 2020

PACIFICORP Electric Operations Cost of Preferred Stock 12 Months Ended December 31, 2020												
Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	Serial Preferred, \$100 Par Value											1
2	7.00% Series	(a)	None	7.000%	18,046	\$1,804,600	(b)	\$1,804,600	100.000%	7.000%	\$126,322	2
3	6.00% Series	(a)	None	6.000%	5,930	\$593,000	(b)	\$593,000	100.000%	6.000%	\$35,580	3
4												4
5	Total Cost of Preferred Stock			6.753%	23,976	\$2,397,600	\$0	\$2,397,600		6.753%	\$161,902	5
6												6
7												7
8												8
9												9
10												10

(a) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.

(b) Original issue expense/premium has been fully amortized or expensed.