

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY, a  
division of PacifiCorp,

Respondent.

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In the Matter of

PACIFIC POWER & LIGHT COMPANY

Petition for an Order Approving Deferral of the  
Washington-Allocated Revenue Requirement  
Associated with the Merwin Fish Collector.

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In the Matter of

PACIFICORP d/b/a PACIFIC POWER & LIGHT  
COMPANY

Petition for an Order Approving Deferral of costs  
Related to Colstrip Outage.

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In the Matter of

PACIFICORP d/b/a PACIFIC POWER & LIGHT  
COMPANY

Petition for an Order Approving Deferral of Costs  
Related to Declining Hydro Generation.

DOCKET UE-140762 and UE-140617  
(consolidated)

DOCKET UE-131384

DOCKET UE-140094

**INITIAL BRIEF ON BEHALF OF COMMISSION STAFF**

January 22, 2015

ROBERT W. FERGUSON  
Attorney General

PATRICK J. OSHIE  
JENNIFER CAMERON-RULKOWSKI  
BRETT SHEARER  
Assistant Attorneys General  
Office of the Attorney General  
Utilities & Transportation Division  
1400 S Evergreen Park Drive S.W.  
P.O. Box 40128  
Olympia, WA 98504-0128  
(360) 664-1188

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## I. INTRODUCTION

1 PacifiCorp d/b/a Pacific Power & Light Company (“PacifiCorp” or “Company”) seeks to increase its base electric prices by \$27.2 million or 8.5 percent.<sup>1</sup> The Company also requests approximately \$6.8 million relating to treatment of several accounting deferrals.<sup>2</sup>

2 Commission Staff (“Staff”) proposes an increase in base electricity rates of approximately \$6.5 million or 2.0 percent.<sup>3</sup> Staff recommends approving approximately \$1.5 million related to the accounting deferrals in this case.<sup>4</sup> Staff’s total revenue requirement is approximately \$8.0 million or 2.51 percent.<sup>5</sup> Staff also proposes a power cost adjustment mechanism (“PCAM”).<sup>6</sup>

3 The differences between the proposals of Staff and the Company present several issues:

- Should the Commission calculate PacifiCorp’s cost of capital using an unnecessarily excessive amount of equity capitalization and an overstated return on equity, despite falling capital costs and the Company’s stable credit rating?
- Should the Commission revisit the Company’s previously-rejected proposal to burden Washington ratepayers with the cost of purchase power agreements (“PPAs”) with Qualified Facilities (“QFs”) in Oregon and California?
- Should the Commission accept the Company’s alternative QF pricing proposals, which contravene Washington policy for treatment of QFs and achieve the same unfair result of burdening Washington ratepayers with the cost of policy decisions made in Oregon and California?

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<sup>1</sup> Reiten, Exh. No. RPR-1T at 2:20.

<sup>2</sup> The Commission consolidated several prior dockets involving PacifiCorp into the current rate case. *Utilities & Transp. Comm’n v. Pacific Power & Light Co.*, Docket UE-140762, Order 05, (June 24, 2014). *See also* Ball, Exh. No. JLB-1T at 4:18-5:3 (including Table 1 – Revenue Requirement as Proposed by Pacific Power”).

<sup>3</sup> This is an increase from Staff’s response case of \$6.1 million. *See* Ball, Exh. No. JLB-1T at 7:1-8 (including Table); Ball, Exh. No. JLB-2 (Revenue Requirement Model). The increase results from Staff’s agreement to various Company rebuttal adjustments as noted in the Final Issues List. Staff will submit a fully revised revenue requirement model (Exhibit JH-2) if directed by the Commission.

<sup>4</sup> This is an increase from Staff’s response case of \$7.7 million. *See* Ball, Exh. No. JLB-1T at 7:1-8 (including Table); Ball, Exh. No. JLB-2 (Revenue Requirement Model). The increase results from Staff’s agreement to various Company rebuttal adjustments.

<sup>5</sup> Ball, Exh. No. JLB-1T at 7:1-8 (including Table); Ball, Exh. No. JLB-2 (Revenue Requirement Model).

<sup>6</sup> Gomez, Exh. No. DCG-1T at 18-24.

- Should the Commission adopt a rate design that nearly doubles the fixed charge but contains no corresponding mechanism to promote conservation?
- Should the Commission accept the Company's proposal to escalate certain costs on the basis of indices that do not specifically relate to operations in the region or in the state of Washington?
- Should the Commission accept the Company's proposed treatment of several accounting adjustments and deferrals?

4 The Company answers each of these questions affirmatively. PacifiCorp's primary argument is to blame the regulatory environment in Washington as presenting a unique set of challenges and lacking "alternative ratemaking mechanisms" that would allow PacifiCorp to earn its authorized return.<sup>7</sup> However, the Company did not present an attrition study, did not present a decoupling mechanism, did not present a comprehensive evaluation of cost allocations, did not propose a multi-year rate plan or expedited rate case process, and did not propose a PCAM, among other shortcomings. PacifiCorp continues to reject the Commission's guidance and Staff proposals on all of the above ratemaking mechanisms. Given that the absence of such alternative ratemaking mechanisms arises in large part due to the Company's own failure to meet its burden with respect to alternative ratemaking proposals, PacifiCorp's laments ring hollow.<sup>8</sup>

5 Staff's recommendations adhere to recent Commission precedent and fundamental regulatory principles. These basic tenets of regulatory ratemaking remain consistent with Washington policies and provide the fundamental bases for Staff's recommendations.

## II. COST OF CAPITAL

6 PacifiCorp asks the Commission to raise the Company's rate of return, which is a key element in the proposed rate increase.

[The rate of return] is the utility's cost of capital, or the amount of money it must spend to obtain the capital it uses to provide regulated products. Rate of return is the weighted

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<sup>7</sup> Dalley, Exh. No. RBD-1T at 5:6-10.

<sup>8</sup> See RCW 80.04.130(4).

average cost of the utility's various sources of capital (the interest it pays on its debt and the rate of return on its equity) that is necessary to permit it to continue to attract the capital required to provide the regulated product or service—in this case, electricity.<sup>9</sup>

To determine the appropriate rate of return, the Commission applies the standards set out by the U.S. Supreme Court in the *Bluefield* and *Hope* decisions.<sup>10</sup> Accordingly, the “return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.”<sup>11</sup> Moreover, the return “should be commensurate with returns on investments in other enterprises having corresponding risks.”<sup>12</sup>

7 PacifiCorp has various sources of capital, including equity, preferred stock, long-term debt, and short-term debt.<sup>13</sup> Staff does not dispute PacifiCorp's embedded cost of long-term debt or its cost of preferred stock.<sup>14</sup> Accordingly the following discussion focuses on the Company's cost of equity as well as its capital structure.

#### A. Capital Structure

8 PacifiCorp seeks to use its actual capital structure to set rates, but does not demonstrate that this is fair to consumer as well as investor interests. PacifiCorp has operated under a

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<sup>9</sup> *People's Org. for Wash. Energy Res. v. Utils. & Transp. Comm'n*, 104 Wn.2d 798, 810, 711 P.2d 319 (1985).

<sup>10</sup> *Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-050684, Order 04, Order Rejecting Tariffs as Filed; Rejecting Stipulation on Net Power Costs; Rejecting, in Part, and Accepting, in Part, Stipulation on Temperature Normalization Adjustment; Determining Cost of Capital, p. 84, ¶ 235 (April 17, 2006); see *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 88 L. Ed. 333, 64 S. Ct. 281 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 67 L. Ed. 1176, 43 S. Ct. 675 (1923).

<sup>11</sup> *Bluefield*, 262 U.S. at 693.

<sup>12</sup> *Hope*, 320 U.S. at 603.

<sup>13</sup> See Williams, BNW-1T at 2, Table 1.

<sup>14</sup> Consistent with the Commission's decision in the 2013 general rate case, which found that the use of a lower level of equity than the Company's actual level gave consideration to the effect of including short-term debt, Staff has not included short-term debt in its proposed cost of capital. Parcell, Exh. No. DCP-1T 22:18-23; see *Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-130043, Order 05, Final Order Rejecting Tariff Sheets; Resolving Contested Issues; Authorizing and Requiring Compliance Filing, pp. 15-16, ¶ 41 (December 4, 2013).

hypothetical capital structure in Washington for a number of years. In 2011, the Commission set PacifiCorp's common equity at 49.1 percent and, since then, PacifiCorp has maintained enviable credit ratings. The equity level of 49.1 percent has maintained the balance of safety and economy, and PacifiCorp has not shown any change in economic conditions or its financial circumstances that would warrant changing the current equity and debt ratios.

9 A company manages its capital structure to maximize the company's value to its shareholders, which, in this case, consist ultimately of Berkshire Hathaway Energy (BHE). Rate-making, however, "involves a balancing of the investor and the consumer interests"<sup>15</sup>; when the Commission sets the capital structure, it must consider both of these interests. An appropriate capital structure strikes a balance between investors' interest in safety and ratepayers' interest in economy. "Safety" refers to the ability of a company to maintain investment quality credit ratings and access to capital, while "economy" corresponds to the lowest overall cost to attract and maintain capital.<sup>16</sup>

**1. The Commission has set hypothetical capital structures for PacifiCorp reaching back to at least 2006.**

10 PacifiCorp is owned by BHE.<sup>17</sup> Shortly after BHE acquired PacifiCorp from its previous owner, Scottish Power,<sup>18</sup> in 2006, the Commission adopted use of a hypothetical capital structure for PacifiCorp that included an equity level of 46 percent.<sup>19</sup> In that order, the Commission observed that PacifiCorp's historical equity share was 43 to 45 percent, which was lower than the industry average. The Commission recognized that PacifiCorp's actual equity share was

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<sup>15</sup> *Hope*, 320 U.S. at 603.

<sup>16</sup> Docket UE-050684, Order 04 at 82, ¶ 230.

<sup>17</sup> Parcell, DCP-1T at 15:14-15 and note 6.

<sup>18</sup> *In the Matter of the Joint Application of MidAmerican Energy Holding Company and PacifiCorp, d/b/a Pacific Power & Light Company for an Order Authorizing Proposed Transaction*, Docket No. UE-051090, Order No. 07, Final Order Approving and Adopting Settlement Stipulation; Requiring Subsequent Filing (February 22, 2006).

<sup>19</sup> Docket UE-050684, Order 04 at 83, ¶ 233.

projected to increase above these historical levels following capital infusions by PacifiCorp's prior owner. Ultimately, however, the Commission looked to the industry average to set PacifiCorp's capital structure, determining that 46 percent was a reasonable equity level based on the average equity capitalization of comparable utilities.<sup>20</sup>

11 In 2011, the issue of capital structure came again before the Commission. PacifiCorp's actual equity level was 52.1 percent. The Commission found that use of the actual capital structure would unfairly favor investor interests over ratepayer interests.<sup>21</sup> Once again, the Commission set a hypothetical capital structure for PacifiCorp, which included an equity level of 49.1 percent.<sup>22</sup>

12 Capital structure was next litigated in PacifiCorp's 2013 general rate case.<sup>23</sup> PacifiCorp proposed using its actual capital structure, which included 52.22 percent equity.<sup>24</sup> The Commission determined that the equity level of 49.1 percent would continue to balance safety and economy and left in place the hypothetical capital structure.<sup>25</sup> The Commission specifically found that this capital structure would allow PacifiCorp to maintain its credit rating and access to capital, citing the fact that PacifiCorp had managed to obtain capital while the rate case was pending at a rate that reduced the Company's as-filed embedded cost of long-term debt.<sup>26</sup>

13 PacifiCorp currently has an actual capitalization level of 51.73 percent.<sup>27</sup> The Company proposes that the Commission discontinue its use of a hypothetical capital structure and use

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<sup>20</sup> Docket UE-050684, Order 04 at 232-33, ¶ 83.

<sup>21</sup> *Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket No. UE-100749, Order 06, Final Order Rejecting Tariff Sheets; Authorizing Increased Rates; and Requiring Compliance Filing, p. 20, ¶ 39 (March 25, 2011).

<sup>22</sup> Docket UE-100749, Order 06 at 22, ¶ 43.

<sup>23</sup> Docket UE-130043, Order 05.

<sup>24</sup> Docket UE-130043, Order 05 at 12-14, ¶¶ 33-38.

<sup>25</sup> Docket UE-130043, Order 05 at 15-16, ¶ 41.

<sup>26</sup> Docket UE-130043, Order 05 at 14, ¶ 39.

<sup>27</sup> Williams, Exh. No. BNW-1T at 2, Table 1.

PacifiCorp's actual capital structure instead. PacifiCorp's actual capital structure, however, remains higher than the equity capitalization the Company needs to attract capital and, therefore, it would be unfair to rate payers to change the status quo and award PacifiCorp a higher equity level and correspondingly higher rates.

**2. PacifiCorp has not demonstrated a change in market conditions that would warrant changing the Company's capital structure.**

14 PacifiCorp contends that, if the Company were capitalized at the level of its current hypothetical capital structure, there would be a downgrade in credit ratings.<sup>28</sup> The fact is, however, that PacifiCorp has operated in Washington with a hypothetical capital structure including an equity level of 49.1 percent since 2011, and its credit ratings have not been downgraded. Its current ratings for senior secured debt are all in the "Single A" category.<sup>29</sup> PacifiCorp has maintained "Single A" ratings on its secured debt with all three rating agencies since at least 2000.<sup>30</sup>

15 Moreover, PacifiCorp's cost of long-term debt has decreased during this period.<sup>31</sup> At the time of the general rate case decided in 2011, PacifiCorp's cost of long-term debt was 5.89 percent.<sup>32</sup> In the 2013 general rate case, PacifiCorp's as-filed cost of long-term debt was 5.37 percent. During the rate case, this cost declined to 5.29 percent.<sup>33</sup> PacifiCorp's current cost of debt is 5.19 percent.<sup>34</sup> It appears that, notwithstanding the application of a hypothetical capital structure with an equity level of 49.1 percent, PacifiCorp has been able to avail itself of declining capital costs and access capital at lower and lower rates. PacifiCorp has not demonstrated any

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<sup>28</sup> Williams, Exh. No. BNW-1T at 12:1-4.

<sup>29</sup> Parcell, Exh. No. DCP-1T at 16:13-17.

<sup>30</sup> Parcell, Exh. No. DCP-1T at 16:20-21.

<sup>31</sup> See Williams, Exh. No. BNW-1T at 17:3-4.

<sup>32</sup> Williams, Exh. No. BNW-1T 17, Table 7. See also UE-100749, Order 06 at ¶ 99.

<sup>33</sup> Docket UE-130043, Order 05 at 14, ¶ 39; Williams, Exh. No. BNW-1T 17, Table 7.

<sup>34</sup> Williams, Exh. No. BNW-1T at 2, Table 1.

facts that would change the ability of the Company with the hypothetical capital structure and current equity level to attract capital at the same rates. In fact, recent history indicates that PacifiCorp has been able to attract financing at increasingly lower costs.

16           Maintaining a hypothetical equity capitalization of 49.1 percent sets PacifiCorp's equity at a level that is consistent with the capitalization of other Washington utilities. The Commission has approved equity levels of 47 percent for Avista and 48 percent for Puget Sound Energy respectively.<sup>35</sup> The equity capitalization approved for Avista and PSE represents a reasonable benchmark for PacifiCorp's equity level. PacifiCorp's equity level is already greater in magnitude than the other two utilities. In addition, PacifiCorp's equity ratio is higher than the 48 percent average of electric utility equity levels reported in AUS Utility Reports<sup>36</sup> and higher than the average of 46 percent in Mr. Strunk's proxy group.<sup>37</sup> Finally, an equity capitalization of 49.1 percent corresponds to the 2013 average common equity ratio of 49 percent in Mr. Parcell's proxy group.<sup>38</sup> The level of 49.1 percent is already at or above the average equity capitalizations of comparable utilities, and PacifiCorp does not demonstrate grounds to award PacifiCorp an even higher equity share.

#### **B. Cost of Equity**

17           PacifiCorp asks the Commission to increase PacifiCorp's return on equity although the evidence in the record strongly suggests that PacifiCorp's return on equity should be decreased. The Commission set PacifiCorp's equity return at 9.5 percent in the 2013 general rate case.<sup>39</sup> Market conditions, investor expectations, and PacifiCorp's comparatively low-risk credit profile

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<sup>35</sup> Williams, Exh. No. BNW-1T at 12, Table 5.

<sup>36</sup> Parcell, Exh. No. DCP-1T at 20:10.

<sup>37</sup> Parcell, Exh. No. DCP-1T at 20:13-15.

<sup>38</sup> Parcell, Exh. No. DCP-1T at 20:13-14.

<sup>39</sup> Docket UE-130043, Order 05 at 27, ¶ 70.

all support reducing the Company's return on equity, as Mr. Parcell recommends. Testifying on behalf of Staff, Mr. Parcell concludes from his analyses that the appropriate cost of equity for PacifiCorp currently is 9.0 percent, which results in an overall return of 7.07 percent.<sup>40</sup> Mr. Strunk, testifying on behalf of PacifiCorp, opines that 10.00 percent is the right number for cost of equity.<sup>41</sup> Mr. Strunk's range, reflecting the lowest and highest appropriate cost of equity, reaches considerably higher than the costs of equity recommended by Mr. Parcell or any of the other expert witnesses testifying on cost of equity. In addition, Mr. Strunk's recommendation of 10.00 percent apparently ignores the credit worthiness of PacifiCorp and the recent decline in interest rates.

**1. PacifiCorp is low-risk, with one of the highest debt ratings in the industry and, therefore, does not require a higher return.**

18 As discussed above, PacifiCorp's debt ratings are among the highest in the industry. Moreover, PacifiCorp has maintained these high debt ratings over time. A higher debt rating indicates a lower risk. Accordingly, if PacifiCorp were publically traded, investors would not require a high return relative to comparable companies in the industry to invest in PacifiCorp.

19 Mr. Strunk protests that PacifiCorp actually is riskier than the companies in his proxy group, in part due to the use of the hypothetical capital structure.<sup>42</sup> Setting equity capitalization at a level lower than the actual capital structure, Mr. Strunk argues, increases PacifiCorp's risk.<sup>43</sup> PacifiCorp has been operating with the same hypothetical capital structure since 2011, however,

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<sup>40</sup> Parcell, Exh. No. DCP-1T at 4:3-5.

<sup>41</sup> Strunk, Exh. No. KGS-17T at 4:20-21. Mr. Williams testifies that a 10.0 percent return on equity and the Company's actual equity capitalization of 51.73 percent results in a 7.67 percent rate of return. Williams, Exh. No. BNW-16T at 1:17-18.

<sup>42</sup> See Strunk, Exh. No. KGS-17T at 19:26-20:3.

<sup>43</sup> Strunk, Exh. No. KGS-17T at 20:1-3.



and its debt ratings have not suffered. Thus, Mr. Strunk's concerns do not seem to be shared by the capital markets, and the hypothetical capital structure has not increased PacifiCorp's risk.

**2. Interest rates declined in 2014 and, therefore, investors will expect lower returns.**

20 Although interest rates continued to decline in 2014,<sup>44</sup> Mr. Strunk maintains that the Commission should increase PacifiCorp's allowed return on equity above the level set in the Company's last general rate case. Interest rates are one of the market conditions that affect cost of capital.<sup>45</sup> The decline in interest rates indicates that investors expect lower returns.<sup>46</sup>

21 In 2014, utility bond yields followed the same downward trend as Treasury issues. The average yield of an A-rated utility bond was 4.81 percent in December 2013; as of November 2014, this yield had declined to 4.09 percent.<sup>47</sup> Notwithstanding predictions that interest rates would rise due to the tapering of the U.S. Reserve's federal bond purchasing program, rates did not rise.<sup>48</sup> The federal policy of purchasing Treasury notes, a type of "quantitative easing," ceased in October 2014.<sup>49</sup> Despite quantitative easing and consistent with other interest rates, utility bond yield averages remained considerably lower than they had been a year earlier.<sup>50</sup>

22 Mr. Strunk acknowledges that interest rates remain low even after quantitative easing but proposes that the Commission raise PacifiCorp's equity return based on further predictions that interest rates really will rise now.<sup>51</sup> When and if interest rates will rise is speculation. What we have in the record is a decline in rates in 2014. This decline in rates indicates an investor expectation that returns will be lower, which supports decreasing PacifiCorp's cost of equity.

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<sup>44</sup> See Parcell, Exh. No. DCP-4 at 4.

<sup>45</sup> Parcell, Exh. No. DCP-1T at 8:11-20.

<sup>46</sup> Parcell, Exh. No. DCP-1T at 11:12-15.

<sup>47</sup> Strunk, Exh. No. KGS-39CX.

<sup>48</sup> Gorman, TR. 346 at 1-12.

<sup>49</sup> See Strunk, Exh. No. KGS-17T at 11:10-11.

<sup>50</sup> Strunk, Exh. No. KGS-39CX.

<sup>51</sup> Strunk, Exh. No. KGS-17T at 11:6-14.

**3. Setting PacifiCorp's cost of equity at 9.0 percent is consistent with the Commission's principle of "gradualism."**

23           Setting PacifiCorp's cost of equity at 9.0 percent, as Staff proposes, is consistent with the policy of gradualism that the Commission articulated when it reduced PacifiCorp's cost of equity from 9.8 to 9.5 percent in the 2013 general rate case. In the 2013 general rate case, the Commission found that the range of reasonable returns reached from 9.0 percent to 9.7 percent. The Commission set PacifiCorp's return on equity closer to the high end of the range of reasonableness based the application of the "principle of gradualism."<sup>52</sup> In the current rate case, this principle is upheld with a gradual reduction in equity return from 9.5 percent to 9.0 percent, consistent with market trends.

**C. Conclusion on Cost of Capital**

24           Staff's recommended hypothetical capital structure with 49.1 percent equity at a return on equity of 9.0 percent balances investor and rate payer interests. PacifiCorp has failed to demonstrate that using its actual capital structure would achieve this balance. Similarly PacifiCorp has failed to demonstrate that its cost of capital has increased. To the contrary, Staff, as well as other parties, has demonstrated that PacifiCorp's equity return should be lower than the rate set in the last general rate case. Staff's cost of equity of 9.0 percent both achieves sufficiency and appropriately reflects PacifiCorp's comparatively low risk.

**III. QUALIFYING FACILITIES COST ALLOCATION**

25           Once again, PacifiCorp demands a unilateral change to Commission approved West Control Area (WCA) interjurisdictional cost allocation methodology. And once again, it seeks to include in Washington rates the costs of Qualifying Facilities (QFs) located in Oregon and

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<sup>52</sup> Docket UE-130043, Order 05 at 25, ¶ 63.

California. It does not matter whether the issue is packaged as a load decrement proposal or an avoided cost modification. The Company's central tenet in its three proposals remains the *special recognition* of these QFs for the purpose of making rates for Washington. The Company sought this same relief in its last rate case but could not justify its proposal. The Commission's QF decision is now before the Washington Court of Appeals (Division II). PacifiCorp is seeking another bite at the apple in this case. But again, it fails to justify why Washington ratepayers should cover the cost of Oregon and California QFs – costs that are the result of Oregon and California policies and not the policies of this state.

26 In its last rate case, the Company proposed that Washington customers should pay the costs of these out-of-state QF agreements.<sup>53</sup> Its proposal in UE-130043 represented a change to the Commission-approved West Control Area (WCA) interjurisdictional cost allocation methodology originally proposed by the Company in 2007,<sup>54</sup> and would have added significant costs to rates paid by Washington ratepayers – an amount approximating \$10.7 million.

27 The Commission's experience with the WCA goes well beyond the matter at hand or the Company's prior case. As the Commission has explained:

The WCA methodology is the only inter-jurisdictional cost allocation methodology proposed since the merger of [Pacific Power & Light] and Utah Power in 1987 that the Commission has approved .... We believe that any changes should be considered in the context of an overall review of that methodology.<sup>55</sup>

28 Prior to the last case, the parties held collaborative discussions to evaluate potential changes to the WCA methodology. But, these meetings were not fruitful.<sup>56</sup> Without the benefit of an agreement, PacifiCorp proposed unilateral changes to the WCA resurrected in this case.

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<sup>53</sup> *Utilities & Transp. Comm'n v. Pacific Power & Light*, UE-130043, Order 05 (December 4, 2013).

<sup>54</sup> *Utilities & Transp. Comm'n v. Pacific Power & Light*, UE-061546 and UE-060817 (consolidated), Order 08, ¶¶49-52 (June 21, 2007). *See also*, Docket UE-130043, Order 05 at ¶80.

<sup>55</sup> Docket UE-130043, Order 05, at ¶92.

<sup>56</sup> *Id.* at ¶82.

29 The test set forth by the Commission to unilaterally change the WCA is straightforward, and was articulated in its Order 05. It stated:

Unless the Company, with or without the agreement of the parties affected by the use of the WCA methodology, *demonstrates that any change proposed more closely aligns the allocation of costs based on causation*, we see no reason to disturb it. For the Commission to endorse any unilateral change, or any change that is disputed, the party advocating the change must make a *detailed and persuasive showing demonstrating that the proposed change is appropriate*.<sup>57</sup>

30 There is no question that the Company clearly understood its burden to justify its proposed changes to the WCA, having expressly acknowledged the need to show ““tangible and quantifiable benefits to Washington’ before [out-of-state] resources can be included in rates.”<sup>58</sup> It just failed to do so.

31 After careful consideration of the record evidence, the Commission rejected the Company’s attempt to foist the costs of Oregon and California QFs onto Washington ratepayers, reasoning in part that Washington ratepayers should not be required to pay QF costs caused by the significantly different renewable development policies in Oregon and California.

32 Having considered the Company’s evidence presented in the last case, the Commission concluded that it had indeed failed to “make a detailed and persuasive showing” that the WCA should be changed.<sup>59</sup> Important to the Commission’s decision now, PacifiCorp presents this same evidence in the case at hand.

**A. The Company Again Asks the Commission to Recognize Oregon and California QFs in the WCA**

33 The Company seeks approval of one of three treatments for Oregon and California QFs. First, it argues that the Commission should reconsider its decision to reject modifying the WCA

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<sup>57</sup> *Id.* at ¶94.

<sup>58</sup> *Id.* at ¶100.

<sup>59</sup> *Id.* at ¶114.

to include the costs of all Oregon and California QFs.<sup>60</sup> It calculates that Washington rates would increase by \$10 million if the Commission reversed its QF decision made in Order 05.<sup>61</sup> It then asks the Commission to re-price the Oregon and California QFs at Washington's avoided costs. Under its re-pricing scheme, the Oregon and California QFs would be re-priced at Washington's historical costs avoided at the time these out-of-state QF PPAs were first executed. The cost to Washington ratepayers under this proposal would be \$7.7 million.<sup>62</sup> Finally, the Company offers its "load decrement" proposal which would remove "the costs and energy of Oregon and California QFs" from its NPC calculation.<sup>63</sup> Its load decrement proposal would place \$5.9 million into Washington rates.<sup>64</sup> The Company's QF proposals share a common single goal – the Commission's express recognition of Oregon and California QFs by either adding them to the WCA or removing them from it.

34 PacifiCorp offers several general arguments to support its refiled proposal to modify the WCA. Like UE-130043, its principal argument supporting all three proposals is that Oregon and California QFs deliver energy to Washington customers.<sup>65</sup> It also argues that these QFs contribute to its *total system* capacity needs and provide resource diversity benefits.<sup>66</sup> Further, it claims that recognizing the out-of-state QFs would be consistent with the WCA because the Company treats these resources like other WCA resources<sup>67</sup> and PURPA mandates recovery of the Company's avoided costs.<sup>68</sup> It argues further that Oregon and California QFs are eligible to

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<sup>60</sup> Duvall, Exh. No. GND-1CT, at 8:7-9.

<sup>61</sup> *Id.* at 12:Table 2.

<sup>62</sup> *Id.*

<sup>63</sup> Duvall, Exh. No. GND – 1CT, at 11:22-23 and 12 1-2.

<sup>64</sup> *Id.* at 12:Table 2.

<sup>65</sup> *Id.* at 8:21-23.

<sup>66</sup> Duvall, Exh No. GND-4T, at 16:10-12 and at 18:22-23.

<sup>67</sup> *Id.* at 3:3-8.

<sup>68</sup> Duvall Exh No. GND-4T, at 14:11-21, 15:1-23 and 16:1- 21.

meet the renewable portfolio standard in the EIA.<sup>69</sup> Finally, it refers to the judicial review of Order 05 now sitting at the Washington Court of Appeals arguing that the issues on appeal are “consistent with the Company’s proposal in this case.”<sup>70</sup>

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As in the 2013 case, PacifiCorp cannot justify its proposal to include Oregon and California QFs in rates. The evidence it presents fails to demonstrate how placing these QFs in rates aligns “the allocation of costs based on causation.”<sup>71</sup> Nor does it make a detailed and persuasive showing that its proposed changes to the WCA are otherwise appropriate.<sup>72</sup> These issues will be discussed below.

1. The reversal of QF situs allocation in the WCA – the Company fails to address the substantive differences between the renewable resource policies of Oregon, California, and Washington

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As noted above, the Commission’s Order 05 determined that Washington ratepayers should not be required to pay out-of-state QF costs driven by the significantly different renewable development policies in Oregon and California. To this point, the Commission articulated:

“[S]itus allocation is fair. Like Oregon and California, Washington has adopted policies favoring and encouraging renewable energy. However, the approaches of the three states are different. Oregon and California have implemented PURPA to carry out policies favoring renewable energy that has resulted in 74 percent of PacifiCorp’s QF power for 2014 coming from contracts PacifiCorp entered in the last 5 years at avoided cost rates for Oregon and California. Washington policy makers have relied less on PURPA and more on renewable portfolio standards and greater use of tax-related incentives to promote renewable energy development in this state.<sup>73</sup> Washington’s policies are paid for by Washington taxpayers or ratepayers, as this state’s policy makers determine. Absent a regionally negotiated alternative arrangement, *Oregon’s and California’s renewable energy policies should be*

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<sup>69</sup> *Id.* at 3:9-11. The EIA is the Energy Independence Act codified as RCW 19.285.

<sup>70</sup> *Id.* at 3:12-13.

<sup>71</sup> Docket UE-130043, Order 05 at ¶94 (December 4, 2013).

<sup>72</sup> *Id.*

<sup>73</sup> *See e.g.*, RCW 82.04.294; RCW 82.16.110-30; RCW 82.08.956-.957, 962-963; and RCW 82.12.956-957, 962-963.

*paid for by the taxpayers and ratepayers of those states, as determined by their policy makers.”<sup>74</sup> (Emphasis added)*

37           Going further, the Commission noted that the Company’s QF proposal was “tantamount to an effort to relieve Oregon and California ratepayers from [the] higher cost[s]” caused by policy decisions made by those states.<sup>75</sup> In fact, the Company conceded that “Washington’s tax-based approach to support the development of distributed generation” was superior to PURPA in that it avoids placing “on ratepayers the full burden of ‘energy sources that are not cost effective for customers.’”<sup>76</sup>

38           The Commission made the correct call when it refused to modify the WCA and pass the costs of Oregon and California QFs to Washington ratepayers in the last case. As the Commission succinctly stated, “each state should bear the costs of its respective renewable energy policies.”<sup>77</sup>

39           In the matter at hand, Mr. Gomez’s testimony directly addressed these significant policy differences, concluding that Washington ratepayers should not be burdened by the Oregon and California QF costs. To this point he said:

“[T]he Company continues to argue that it is only fair that Washington rate payers absorb the additional NPC costs resulting from non-Washington QF PPAs in spite of the fact that these added costs are directly attributable to other states’ independent and varying policies when implementing PURPA. For example, the policies established by the Oregon Commission weigh heavily in favor of certain wind resources. As a result, these resources are priced significantly above market prices and the rates approved by the Commission for similar resources located in Washington. The high costs for these resources whether approved by the Oregon or California utility commissions have nothing to do with Washington ratepayers’ contribution to costs.”<sup>78</sup>

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<sup>74</sup> Docket UE-130043, Order 05, at ¶111 (December 4, 2013).

<sup>75</sup> *Id.* at ¶112.

<sup>76</sup> *Id.* at ¶112.

<sup>77</sup> *Id.* at ¶113.

<sup>78</sup> Gomez, Exh. No. DCC-1CT, 11:3-12.

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Mr. Gomez went on to explain that the Company's arguments supporting its QF proposals failed to address the "facts presented in the last case regarding how individual state utility commissions can, and do, determine the amount and types of QF power that utilities subject to their jurisdiction must purchase."<sup>79</sup> He concluded that the Company's "testimony ... offers nothing new for the Commission to consider regarding the subject of situs allocation" of the Oregon and California QFs.<sup>80</sup> Mr. Gomez is absolutely correct.

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The Commission's Order 05 identified the distinct policy differences between Oregon, California and Washington that have affected the development of renewable resources in the respective states. It clearly implicated these significant policy differences when it refused to modify the WCA to include Oregon and California QFs and burden Washington ratepayers with their higher costs.<sup>81</sup>

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PacifiCorp could have presented evidence that the Oregon and California renewable policies have materially changed since the Commission's Order 05, but it did not. Importantly, the Company offered no substantive evidence on this critical issue, other than to argue that both Oregon and Washington have used PURPA to "promote distributed generation."<sup>82</sup> Even this "observation" was bereft of any specific examples. One can only conclude from this glaring omission that Oregon and California's renewable policies have not materially changed. Instead of comparing the relevant state policies, PacifiCorp conflated the Commission's order by implying that the Commission believed the Company's avoided costs had somehow been

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<sup>79</sup> *Id.* at 11:13-16.

<sup>80</sup> *Id.* at 11:16-17.

<sup>81</sup> Docket UE-130043, Order 05 at ¶111 (December 4, 2013).

<sup>82</sup> Duval Exh No. GND-4T at 21:17-18.



*manipulated* by Oregon and California regulators by including avoided cost “adders” to promote specific energy policies.<sup>83</sup> Nothing could be farther from the truth.

43           The Commission’s Order 05 simply recognized the real and substantial differences between Oregon and California’s QF policies and those of Washington. As pointed out by Mr. Gomez in this case, these real and substantial policy differences result in Oregon and California QF prices “significantly higher than would be the case if they were priced at Washington avoided cost rates.”<sup>84</sup> The Company offers nothing to rebut the avoided cost differences between the jurisdictions.

44           For the reasons expressed, PacifiCorp has failed to demonstrate with detailed and persuasive evidence that its proposal to modify the WCA would effectively allocate costs based on causation. In fact, the costs it would impose upon Washington ratepayers are deeply rooted in the significant policy differences between the states. These policy differences result in significantly higher avoided costs and therefore higher prices for QFs located in Oregon and California. Consistent with PURPA, Oregon and California have set the Company’s avoided costs in those states, and the ratepayers in those states should bear the burden of those avoided cost decisions – not the ratepayers in Washington.

2.       PURPA does not mandate that Washington ratepayers pay the avoided costs determined by Oregon and California regulators

45           PacifiCorp again leans on its PURPA obligations relative to its Oregon and California QFs to justify including these resources in Washington rates. First, it mischaracterizes the Commission’s decision in its last rate case by claiming that re-pricing “out-of-state QF PPAs at current market prices is inconsistent with PURPA’s requirement ... that utilities purchase ... QF

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<sup>83</sup> Duvall Exh No. GND-4T at 20 18-20 and at 21:7-9.

<sup>84</sup> Docket UE-130043, Order 05, at ¶113 (December 4, 2013). *See also*, Gomez, Exh. No. DCG-1CT, 11:8-10.

[resources] at the utility' avoided costs.”<sup>85</sup> Similar references to PURPA are made to support this specious re-pricing argument.<sup>86</sup> Of course, the Commission’s Order 05 did not re-price these resources – it simply did not include them in the WCA. PacifiCorp goes on to reference PURPA’s requirement that QF prices are set at the Company’s avoided costs, concluding that “it is unreasonable to exclude the QF PPAs from rates.”<sup>87</sup> The Company misses the point. PURPA does not obligate the Commission to include Oregon and California QFs in rates or to in any way modify the WCA to the Company’s liking.

46 As background, PURPA requires utilities to purchase electric energy from QFs at rates equal to the utility’s full avoided cost. In other words, the cost that the utility avoids by not having to build or otherwise acquire an equivalent resource.<sup>88</sup> This requirement protects both utilities and ratepayers from paying QF costs that exceed the utility’s cost to produce similar capacity or energy.

47 Under PURPA, state regulators set a company’s avoided costs by a examining a utility’s cost to serve a particular state. Further, states are provided a “wide degree of latitude” when setting a utility’s avoided costs.<sup>89</sup> As a result, state-specific policies drive avoided cost determinations to a large extent.<sup>90</sup> Accordingly, a single utility’s avoided costs may differ significantly between the states in which it serves.<sup>91</sup>

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<sup>85</sup> Duvall, Exh. No. GND-4T, at 14:15-16 and at 15:1-2.

<sup>86</sup> Cf, Duvall, Exh. No. GND-4T, at 15:16-18, at 16:17-22, and at 17:4-6.

<sup>87</sup> Duvall, Exh. No. GND-4T, at 20:9.

<sup>88</sup> 18 C.F.R. §§ 292.101(b)(6) and 292.304.

<sup>89</sup> 18 C.F.R. § 292.304(c); *In re Cal. Pub. Utils. Comm’n*, 133 FERC ¶ 61059, 2010 WL 4144227 (Oct. 21, 2010); *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 416, 103 S. Ct. 1921, 76 L. Ed. 2d 22 (1983); *Indep. Energy Producers Ass’n, Inc. v. Cal. Pub. Utils. Comm’n*, 36 F.3d 848, 856 (9th Cir. 1994).

<sup>90</sup> See 18 C.F.R. § 292.304(c). State-specific policies outside the context of PURPA also have a substantial effect on avoided cost prices. *In re Cal. Pub. Utilities Comm’n*, 133 F.E.R.C. ¶ 61059, 61268, 2010 WL 4144227 (Oct. 21, 2010).

<sup>91</sup> The dramatic difference between the Company’s Washington avoided costs and those set by Oregon and California provides an excellent example of how avoided costs differ between states.

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Importantly, neither PURPA nor its implementing regulations speak to whether the avoided costs set by one state can obligate a second state to include those avoided costs in its rates. In fact, FERC has expressly acknowledged that “existing rules under PURPA do not address how states should implement [FERC’s] avoided cost rules for utilities operating in more than one state.”<sup>92</sup> Because federal law is completely silent on how out-of-state avoided costs should be allocated by a multi-state utility, the Commission should reject any notion that PURPA *mandates* it to accept the avoided costs established by Oregon and California for the purpose of setting rates in Washington.

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As PURPA provides no support for PacifiCorp, the Commission can be assured that its decision to reject the inclusion of Oregon and California QFs in Washington rates is not only PURPA compliant but was correctly decided given the significant policy differences between the states. It is these differences that account for the “significantly above market” costs of Oregon and California QFs.<sup>93</sup>

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As the Commission is aware, its decision has been appealed to the Washington Court of Appeals (District II).<sup>94</sup> As noted earlier in this brief, the Commission made the correct call when it maintained the original design of the WCA – a design initially proposed by the Company. The policy differences relative to these QFs contributed prominently to the Commission’s conclusion’s in Order 05. This gulf between the Company’s WCA states still exist today. Whether in court or before the Commission, the burden is on the Company to demonstrate that the Commission’s treatment of Oregon and California QFs is unsound. It offered nothing new in this case to do so.

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<sup>92</sup> See *Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities*, FERC Rep. ¶ 32,457 (CCH), 2009 WL 4645881 (proposed Mar. 16, 1988).

<sup>93</sup> Gomez, Exh. No. DCG – 1CT, at 11:8-12.

<sup>94</sup> *PacifiCorp v WUTC*, No. 46009-2-II.

**B. The Company's Proposal to Re-Price Oregon and California QFs Is Inconsistent with Washington's QF Policies and Rules and PURPA**

51 PacifiCorp proposes to re-price the PPAs of its Oregon and California QFs “using the Washington avoided cost rates in effect at the time of PPA execution.”<sup>95</sup> It offers this alternative as an attempt to remove “the impact of differences in individual state commission approaches to determining avoided cost prices.”<sup>96</sup> No matter how intended, this proposal would still result in a \$7.7 million increase to Washington rates. If truly intended to make Washington ratepayers indifferent to the Oregon and California QFs<sup>97</sup>, this proposal fails to do so.

1. The hypothetical avoided costs proposed by the Company for Oregon and California QFs cannot be reconciled with the Company's actual avoided costs for Washington

52 The Company makes annual PURPA-related filings under its Schedule 37 that include the Company's estimated avoided costs for its Washington jurisdiction.<sup>98</sup> For 2014, the Company's Schedule 37 filing established its avoided costs at \$32.56 at MWh.<sup>99</sup> Under the Company's re-pricing proposal, the nominal avoided cost for its Oregon and California QFs would be \$68.58 MWh – over double its actual avoided costs for Washington.<sup>100</sup> This stark difference results from the Company's manipulation of the QF resources, and the failure to comport its proposal to Washington's PURPA rules and its own Schedule 37. As a result, the Company's re-pricing proposal bears no resemblance to its actual avoided costs for Washington nor does it serve to make ratepayers indifferent to its adoption.

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<sup>95</sup> Duvall, Exh. No. GND-1CT, at 12:3-5. In effect, its proposal represents an attempt to re-set these QFs' avoided costs for the purpose of making rates in Washington.

<sup>96</sup> Duvall, Exh. No. GND-1CT, at 14:1-3.

<sup>97</sup> Duvall, Exh. No. GND-4T, at 25:20-21.

<sup>98</sup> WAC 480-107-055 (1).

<sup>99</sup> Pacific Power and Light, Tariff WN U-75, Schedule 37, Third Revised Sheet Number 37.2.

<sup>100</sup> Tr. at 0552: 8-15. See also Confidential response to Bench Request No. 3, Attachment 3.1.

The Company's re-pricing proposal attempts to re-create from its PURPA history in Washington an alternative avoided cost for its Oregon and California QFs. However, it cannot do so without manipulating its historical avoided cost data.<sup>101</sup> For example, under Washington's current PURPA rules, Washington QFs have a maximum five-year term.<sup>102</sup> At the end of this period, the Company's then current avoided costs would determine the new PURPA contract price for the QF.<sup>103</sup> In contrast, Oregon allows standard QF offers of up to 20 years.<sup>104</sup> Under its re-pricing scheme, the Company creates a fictitious avoided cost for historical contracts by assuming the Commission would have "re-priced" existing PURPA contracts coincidentally with the QF PPAs executed in Oregon and California.<sup>105</sup> To add more costs to its proposal, it included an inflation factor to some historical prices, even though it admitted that its avoided costs are trending downward.<sup>106</sup>

The Company claims its re-pricing scheme would make Washington ratepayers "indifferent" to its proposal.<sup>107</sup> A \$7.7 million power cost increase added to rates would hardly make Washington ratepayers indifferent.<sup>108</sup> By asking today's ratepayers to pay speculative historical prices for current service, the Company seeks relief that is both unconscionable and would be tantamount to retroactive ratemaking.

<sup>101</sup> See Confidential response to Bench Request No. 3, Attachment 3.1.

<sup>102</sup> Duvall, TR, at 427:19-23. As another example, the Company's re-pricing scheme ignores the 2 MW project nameplate capacity limit set forth in its Schedule 37. Almost 92 percent of the power in the re-pricing proposal modeled for the rate year is coming from QF PPAs larger than 2MW. This represents almost 90 percent of the revenue requirement proposed by the Company under its re-pricing proposal. Under Chapter 480-107 WAC, the acquisition process for these larger projects may result in pricing and terms that are substantially different than what would be possible under the schedule. It may also result in no contract at all if these larger QF decide to participate in an RFP and compete against other bidders. The Company's testimony is silent on this point.

<sup>103</sup> Duvall, TR, at 429:7-13.

<sup>104</sup> Duvall, TR, at 428:1-3. See also, Docket UE-130043, Order 05 at ¶108.

<sup>105</sup> TR, at 439:8-11.

<sup>106</sup> TR, at 428:16-18. Adjusting avoided costs upward for inflation ignores the reality of an actual downward direction of avoided costs due to slower load growth and decreasing market prices for wholesale energy and gas.

<sup>107</sup> TR, at 439:11-12.

<sup>108</sup> One can only speculate that such indifference could have existed when these contracts were first executed.

2. The avoided costs for the Oregon and California QFs have been established by the Oregon and California regulators and the Commission should not attempt to re-set them

55 As shown above, PacifiCorp's re-pricing proposal is based on evidence that fails to accurately represent the Company's historical avoided costs in Washington. Furthermore, its re-pricing proposal is entirely inconsistent with PURPA.

56 FERC has established that the statutory maximum rate allowed under Section 210 is a utility's avoided cost. Thus, the rules insure that utilities purchase QF power at rates that are just and reasonable, in the public interest, and nondiscriminatory to QFs; however, such rates must not exceed the "incremental cost to the electric utility of alternative electric energy."<sup>109</sup> This provision has been imposed to insure that utility ratepayers do not subsidize QFs.<sup>110</sup> Under PURPA, the avoided cost rates for purchases by an inter-jurisdictional utility are established by the state in which the purchasing utility is located.<sup>111</sup> Consistent with this requirement, the QF PPA's at issue here have already been approved by Oregon and California regulators at prices based on the Company's avoided costs *in those states*. Importantly, these QFs are not subject to multiple contracts established by each state served by the Company. And, as noted above, nothing in PURPA dictates that Washington allocate the Oregon and California QF costs to Washington ratepayers.

57 The Oregon and California regulator's approval of these agreements were founded in the laws, rules, and policies of those jurisdictions. This is not a fact in dispute. PacifiCorp's re-pricing proposal essentially asks the Commission to ignore its own resource planning and acquisition laws, rules and policies, and in their stead, replace them with those adopted by

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<sup>109</sup> 16 U.S.C. § 824a-3(b).

<sup>110</sup> 16 U.S.C. § 824a-3(b).

<sup>111</sup> 16 U.S.C. § 824a-3(f).

Oregon and California.<sup>112</sup> For example, Washington’s policies encourage small cogeneration and renewable development through need-based requests.<sup>113</sup> To this end, the Company’s Schedule 37 includes a 2 MW project nameplate capacity limit. But, its re-pricing proposal asks the Commission to ignore Schedule 37’s MW ceiling and replace it with Oregon and California’s 10 and 20 MW limits.<sup>114</sup> This result would not only depart from this Commission’s established policy (and resulting tariffs), but would go further to ask Washington ratepayers to pay for QF power at an amount significantly above the Company’s actual avoided cost in Washington. This result is inconsistent with PURPA and its requirement that ratepayer’s be indifferent to PURPA resources.

58           The Commission can avoid all these obstacles by upholding its decision in UE-130043 and exclude the Oregon and California QFs from Washington rates. There, the Commission determined that the Company’s QF proposal represented an attempt to shift the higher cost burden of these out-of-state resources to Washington ratepayers – a result it concluded was “fundamentally unfair”.<sup>115</sup> The Company’s re-pricing would also be unfair to Washington ratepayers and should be rejected.

### **C.     The Company’s Load Decrement Proposal Should Also Be Rejected**

59           PacifiCorp’s “load decrement” proposal would exclude the cost and energy of Oregon and California QFs from both the Company’s NPC and its inter-jurisdictional allocation

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<sup>112</sup> See WAC 480-100-238 and Chapter 480-107 WAC.

<sup>113</sup> In recent years, the Company’s Schedule 37 filings were directed to small projects that were eligible to seek a PPA with the Company at the avoided costs set forth in its tariff.

<sup>114</sup> See Bench Request 3. Almost 92 percent of the power in the re-pricing proposal modeled for the rate year is coming from QF PPAs larger than 2MW. This represents almost 90 percent of the revenue requirement proposed by the Company under its re-pricing proposal. Under Chapter 480-107 WAC, the acquisition process for these larger projects may result in pricing and terms that are substantially different than what would be possible under the schedule. It may also result in no contract at all if these larger QF decide to participate in an RFP and compete against other bidders.

<sup>115</sup> Docket UE-130043, Order 05 at ¶112.

factors.<sup>116</sup> As rationalized by the Company, the Commission refused to recognize the Company's Oregon and California QFs in its Order 05. For this reason, the Company proposal would remove their costs and related energy from the WCA.<sup>117</sup> Next, it argues that the Oregon and California QFs were "deemed" by the Commission to "serve only customers in those states."<sup>118</sup> Thus, it would likewise remove the retail load served by these resources and then subtract the same from the "energy and peak loads" used to allocate system costs under the WCA.<sup>119</sup> If adopted it would add approximately \$6.0 million to Washington rates.

60 The Company's load decrement proposal is based on a misunderstanding of the Commission's Order 05, and represents a continued effort to re-define the QF cost allocation issue as one dependent upon power flows and not the policies reflected in the WCA. Neither of these arguments stand up under scrutiny.

61 As pointed out by Mr. Gomez, the Commission's Order 05 did not treat the Oregon and Washington QFs as if they served only those states.<sup>120</sup> To this very point, the Commission's Order 05 noted:

Staff's opposition, thus, does not focus on the question whether QFs in Oregon and California provide "undifferentiated generation" in the WCA. Instead, Staff's focus is on the underlying purpose of the WCA's situs allocation of QF cost. That purpose, according to Staff, is to recognize that the three state's approaches to implementing PURPA's QF requirements are different, having different policy goals, achieving different ends, and resulting in different costs.<sup>121</sup>

62 Along these same lines, Mr. Gomez testified that:

The load-decrement proposal asks the Commission to accept the Company's already rejected argument that the flow of power to serve load is the sole basis for allocating

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<sup>116</sup> Duvall, Exh. No. GND-1CT, at 11:22-23 and 12:1-2.

<sup>117</sup> Duvall, Exh. No. GND-1CT, at 12:13-15.

<sup>118</sup> Duvall, Exh. No. GND-1CT, at 12:15-16.

<sup>119</sup> Duvall, Exh. No. GND-1CT, at 12:16-20.

<sup>120</sup> Gomez, Exh. No. DCG-1T, at 10:18-25 and at 11:1-2

<sup>121</sup> Docket UE-130043, Order 05 at ¶101.



costs in the WCA and not cost-causation. Pacific Power continues to pursue this notion in spite of the ample record and past Commission orders establishing the principles of cost allocation for the WCA.<sup>122</sup>

63 He went on to testify that the Commission “has acknowledged that these resources serve WCA customers”<sup>123</sup>, and “did not treat these QFs as being non-existent.”<sup>124</sup> Through his testimony, Staff clearly demonstrates that Order 05 did not expressly exclude the Oregon and California QFs from the WCA based on whether or not they served Washington. Rather, the Commission’s Order expressly excluded the costs of these resources in rates because of the significant policy differences between the respective states.

64 Furthermore, GRID does not recognize these resources in its cost calculation. As a result, the gap left by these resources is captured by GRID as market purchases and priced at market rates.<sup>125</sup> Therefore, the Company indeed recovers costs related to these resources, but not pursuant to PURPA or the WCA. PacifiCorp’s load decrement proposal is a radical reaction to the Commission’s continued support for the WCA and should be rejected.

**D. The Commission is not Obligated to Decide the Company’s Repeated Petition to Include Oregon and California QF Resources in Washington Rates**

65 There is no question that PacifiCorp clearly seeks to re-litigate the Commission’s decision in UE-130043 to reject the inclusion of Oregon and California QFs in the WCA. As explained above, each alternative proffered by the Company asks the Commission to expressly recognize these QFs as included in the WCA, whether in whole or part or by recognizing these resources and expressly removing them from the WCA. As the recognition of these QF

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<sup>122</sup> Gomez, Exh. No. DCG-1CT at 15:4-8.

<sup>123</sup> Gomez, Exh. No. DCG-1CT at 15:12-13.

<sup>124</sup> Gomez, Exh. No. DCG-1CT at 15:10-11.

<sup>125</sup> Gomez, Exh. No. DCG-1CT at 15:14-15.

resources was the very issue litigated in the Company's prior rate case, the Commission is not obligated to decide this issue in this proceeding.

66 RCW 80.04.200 states, in pertinent part:

Any public service company affected by any order of the commission, and deeming itself aggrieved, may, *after the expiration of two years from the date of such order taking effect*, petition the commission for a rehearing upon the matters involved in such order, setting forth in such petition the grounds and reasons for such rehearing, which grounds and reasons may comprise and consist of changed conditions ... , or that the effect of such order has been such as was not contemplated by the commission or the petitioner, or for any good and sufficient cause which for any reason was not considered and determined in such former hearing. (Emphasis added)

67 The unambiguous language of this statute sets forth a two-year period during which an issue decided by the Commission cannot be reheard. The meaning of this statute was tested in *US West Communications, Inc. v WUTC*.<sup>126</sup> Here, US West challenged the Commission's rejection of its depreciation case made a part of its 1995 general rate case. Shortly before the general rate case, the Commission had ruled on US West's previous depreciation case filed in 1994. US West appealed the Commission's refusal to rehear the depreciation issues decided earlier. The court rejected US West's argument that the Commission was required to hear its depreciation evidence pursuant to the APA.<sup>127</sup>

68 To this issue the Court concluded:

The same issues which were considered in the depreciation case are the issues the Company sought to introduce in the rate case. Therefore, under RCW 80.04.020, the Commission did not have to rehear those issues in the rate case only months after they had been considered in the depreciation case. Under this statute, whether or not US West had "new" evidence or wished to argue that conditions had changed with regard to competition, *the Commission was not obligated to hear the issues again within the two-year period*.<sup>128</sup> (Emphasis added)

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<sup>126</sup> *US West Communications, Inc. v WUTC*, 134 Wn.2d 74, 105, 949 P.2d 1337 (1997).

<sup>127</sup> See RCW 34.05.570(3)(f)

<sup>128</sup> *US West Communications, Inc. v WUTC*, 134 Wn.2d 74, 105, 949 P.2d 1337 (1997)

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PacifiCorp’s QF proposal also falls within the purview of RCW 80.04.200. The QF issues were decided in the Company’s 2013 rate case. In this case, it brings these same issues and arguments back before the Commission well within the two-year window set forth in the statute.<sup>129</sup> The Company seeks another bite at the apple and the Commission is under no obligation to give it that benefit.

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RCW 80.04.200 gives the Commission the discretion to set these issues aside until the two-year period set forth in the statute has run. Due process does not require back-to-back hearings on the same issues, or an infinite number of hearings, ending only when the Company gets the full relief it seeks.

**IV. STAFF’S PCAM PROPOSAL**

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PacifiCorp proposed a PCAM in its last general rate case.<sup>130</sup> Ignoring Commission precedent, it did not include dead bands and sharing bands in its PCAM design. As a result, its design was rejected by the Commission.<sup>131</sup> In this case, Staff offers a PCAM that is correctly designed, and includes both dead bands and sharing bands.

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The PCAM design proposed by Staff is nearly identical to Avista’s Energy Recovery Mechanism (ERM).<sup>132</sup> It has, however, been conformed to the Company’s particular circumstances,<sup>133</sup> and fully comports with the Commission’s PCAM requirements.

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<sup>129</sup> UE-130043 was decided on December 4, 2013. This case was filed on May 1, 2014.

<sup>130</sup> Docket UE-130043, Order 05.

<sup>131</sup> *Id.* at ¶173.

<sup>132</sup> *Utilities & Transp. Comm’n v. Avista Corp.*, Docket UE-011595, Fifth Supplemental Order at ¶¶34-40 (June 18, 2002).

<sup>133</sup> Gomez, Exh. No. DCG-1CT, at 22:14-16. For example, the \$25 million deadband in Staff’s proposed PCAM for PacifiCorp reflects about five percent of the average NPC costs for the Company on a WCA basis. When allocated to WA, the percentage deadband result is identical to Avista’s deadband of 4.3 percent. Avista’s total system NPC is about 1/3 of PacifiCorp’s WCA NPC.

The Commission's "test" for the Company's PCAM design requires satisfying two general principles. As identified by Mr. Gomez, a PCAM design must:

- Demonstrate the process, accounting, and reliability of the computer-generated "actual costs" that the Company [proposes] ... to use in the annual PCAM true-up; and
- Refine the PCAM design to reflect asymmetry of power cost distribution.<sup>134</sup>

Staff believes PacifiCorp's recent decision to "report actual NPC per its books and records" has reasonably resolved the Company's need to support a PCAM filing with actual costs.<sup>135</sup> Therefore, the Commission's first principle has been satisfied. The Commission's second principle is satisfied through the use of properly designed dead bands and sharing bands.<sup>136</sup>

The Commission has clearly enunciated the requirement that a PCAM must be designed with dead bands and sharing bands.<sup>137</sup> The Commission views these elements as necessary to "apportion risk equitably" between ratepayers and shareholders.<sup>138</sup> The Commission went on to observe that such elements "motivate management to effectively manage or even reduce power costs."<sup>139</sup> In this proceeding, Mr. Dalley confirmed that PacifiCorp currently has power cost adjustment mechanisms in all of its other state jurisdictions with the exception of Washington.<sup>140</sup> And, with the exception of California, the various mechanisms used in its other jurisdictions employ sharing bands, dead bands and other measures to incent the Company to manage its

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<sup>134</sup> Gomez, Exh. No. DCG-1CT at 19:18-20 and 20:1-4. Citing *Utilities & Transp. Comm'n v. Pacific Power*, Docket UE-061546, Order 08 at ¶111 (June 21, 2007). The Commission also stated that any proposal must include a provision that a general rate case must be filed within a certain term; and must direct that any water-year adjustment for power cost normalization be consistent with the way the PCAM design reflects the asymmetric power cost distribution.

<sup>135</sup> *Id.* at 20 at 11-14.

<sup>136</sup> *Id.* at 20 at 15-17.

<sup>137</sup> Docket UE-130043, Order 05 at ¶¶170-171.

<sup>138</sup> Docket UE-050684, Order 04 at ¶96.

<sup>139</sup> *Id.* at ¶96.

<sup>140</sup> Dalley, TR. at 391:16-19.

power costs.<sup>141</sup> PacifiCorp offers no satisfactory reason why Staff's PCAM design should be rejected.

76 Consistent with the Commission's clear direction, Staff's PCAM design includes dead bands of "\$25 million on a WCA basis", and asymmetrical sharing bands of 50/50 (customers/Company) for power costs under recovery and 75/25 (customers/Company) for power costs over recovery.<sup>142</sup> Like Avista's ERM, Staff's PCAM design includes "all components of NPC as traditionally defined in the Company's general rate cases and modeled in the Company's GRID model."<sup>143</sup> Like the ERM, it also includes a retail revenue adjustment.<sup>144</sup>

77 From a ratemaking perspective, all actual rate adjustments would occur after the deferrals reach a level of 10 percent of the Company's base retail revenues, and spread consistent with the rate spread in effect at the time – with the exception of street and area lighting.<sup>145</sup> Finally, Staff recommends that the Company file quarterly and annual reports covering PCAM results.<sup>146</sup>

78 To summarize, Staff's PCAM is correctly designed and includes dead bands and sharing bands that would protect both PacifiCorp and its ratepayers from normal variability caused by changes in fuel costs, weather (including wind), hydro flows that could move costs up or down from the baseline. So long as the variability falls within the dead bands, rates would not have to be changed as a result of normal variations in costs. As noted elsewhere in this brief, the Company's RTTM and Hydro Tracker should be rejected for the reasons expressed therein. The reasonable alternative to these flawed cost recovery mechanisms is a full PCAM. To that end, Staff's PCAM proposal would fairly compensate PacifiCorp for the effects of wind and weather

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<sup>141</sup> *Id.* at 391:20-25 and at 392:1-3.

<sup>142</sup> Gomez, Exh. No. DCG-1CT at 22:12-22 and at 23:1-2.

<sup>143</sup> *Id.* at 21 at 2-16.

<sup>144</sup> *Id.* at 21 at 21-22 and 22:1-10.

<sup>145</sup> *Id.* at 23 at 12-23 and at 24:1-5. Street and area lighting rate changes would be spread on a uniform basis.

<sup>146</sup> *Id.* at 24 at 10-13 and 8-9.

and protect ratepayers from normal variability associated with renewable and hydro resources.

In short, Staff's PCAM is the correct mechanism to deal with the resource variability complained of by the Company.

79 Finally, the sharing bands proposed by Staff would significantly reduce the Company's power cost risk by ensuring that the cost of more extreme market price increases or decreases are shared by the Company and ratepayers at a defined percentage. Thus, Staff's PCAM proposal would produce the correct balance of risk between the Company and ratepayers – a balance similar to that already approved by the Commission in Avista's ERM and PSE's PCA.<sup>147</sup>

## V. HYDRO TRACKER DEFERRAL

80 In Docket UE-140094, the Company requested approval to defer replacement power costs "associated with significant declines in hydro generation due to abnormally dry weather conditions and low water availability."<sup>148</sup> This matter was consolidated with the Company's general rate case, along with the other outstanding deferral petitions dealing with the Merwin Project and operations at the Colstrip Coal facility.<sup>149</sup>

81 Under the Company's hydro deferral mechanism (Hydro Tracker), the forecast hydro generation for a given period would be compared with end of period actuals.<sup>150</sup> The difference between its hydro generation forecast and actuals would be monetized by applying either market prices or the cost of the Company's thermal generators needed to "compensate for the

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<sup>147</sup> *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-011570 and UG-011571, Twelfth Supplemental Order ¶¶ 22-29 and 56. (June 20, 2002).

<sup>148</sup> *In the Matter of PacifiCorp d/b/a Pacific Power & Light Company Petition for an Order Approving Deferral of Costs Related to Declining Hydro Generation*, Docket UE-140094, Petition (January 17, 2014) at 2: ¶4.

<sup>149</sup> *Order 05: Order Granting Pacific Power & Light Company's Motion and Consolidating Dockets UE-131384 and UE-140094 With Dockets UE-140762 and 140617* (June 24, 2014).

<sup>150</sup> *In the Matter of PacifiCorp d/b/a Pacific Power & Light Company Petition for an Order Approving Deferral of Costs Related to Declining Hydro Generation*, Docket UE-140094 Petition (January 17, 2014) at 3:¶7.

shortfall.”<sup>151</sup> The “costs” would be recovered from ratepayers when the Company’s “base net power costs are reset”.<sup>152</sup>

82 The Commission should reject this proposal. As demonstrated by Staff, the Company’s hydro generation is following a normal pattern for the period. Further, the Hydro Tracker would provide “dollar for dollar” compensation for differences between its hydro forecast and actuals. The Commission has rejected this tracker mechanism design in the past and should again here.

**A. The Company Fails to Demonstrate that it is Experiencing a Significant Decline in its Hydro Generation Output**

83 The Company’s deferral petition alleged that “abnormally dry weather and low water availability” has resulted in significant declines in its hydro generation.<sup>153</sup> The Company failed to support this conclusion with substantial and specific evidence detailing a significant output decline of its hydro generators. In fact, the deferral petition lacked any detailed information regarding its hydro output and why it was occurring. Even the Company’s direct testimony ignored these important facts.<sup>154</sup>

84 In response to PacifiCorp’s direct testimony, Mr. Gomez performed a detailed analysis of the Company’s hydro generator performance. His testimony is based in part on the Company’s responses to two data requests – one submitted by Public Counsel and one submitted by Staff.<sup>155</sup>

85 These responses showed that its “actual hydro generation (January – August 2014)” when combined with the Company’s forecast for the “remainder of the proposed deferral period

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<sup>151</sup> *Id.* at 2:¶4. The Company speculated that it would need “approximately \$15 million” in additional power supply costs to make up the difference on a total-company basis.

<sup>152</sup> *Id.* at 3:¶8

<sup>153</sup> *Id.* at 2:¶4

<sup>154</sup> The Company’s direct testimony on this issue was largely limited to its accounting witness, Ms. Siores, who merely included the Hydro Tracker in her summary of the Company’s estimated deferral amounts, and the Company’s proposed ratemaking treatment. *See* Siores, Exh. No. NCS-1T at 8, Table 1 and at 9:12-14

<sup>155</sup> Gomez, Exh. No. DCG-1CT at 17:6-7 and 10-12.

(September- December 2014)” would result in hydro generator output within 2.9 percent of the amount placed into rates.<sup>156</sup> This result (2.9 percent of forecast) was significantly better than the performance of the Company from 2007 to 2013. Over this period, the difference between actual hydro generation and the amount in rates averaged about 9 percent.<sup>157</sup> From these results, Mr. Gomez concluded that the Company’s hydro performance during the deferral period (2.9 percent as compared with 9.0 percent) was “well within an acceptable range.”<sup>158</sup> In response, the Company provided an updated analysis of its hydro output, and concluded that the difference between actual hydro generation and the amount in rates would be “approximately 7.6 percent” for all of 2014.<sup>159</sup> In a recent update, the difference between hydro generation in rates and actual now stands at 7.2 percent (4.9 percent for the deferral period).<sup>160</sup> All updates considered, the Company’s actual hydro generation still falls within Staff’s acceptable range of 9 percent of forecast. In addition, Mr. Mullins points out that PacifiCorp’s actual hydro generation was 7 percent and 6 percent above what was included in rates in 2011 and 2012. Yet, the Company made no effort to return the savings attributable to the higher than average hydro conditions in those years.<sup>161</sup>

86           The Company seeks extraordinary relief. It should bring more than average results to the table to secure it. In fact, the Company and Staff can agree that the Company’s performance during the deferral period is expected to be *better than average*. The Company blames “abnormal hydro conditions” in 2013 and 2014 as the cause of its missed forecasts.<sup>162</sup> However,

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<sup>156</sup> Gomez, Exh. No. DCG-1CT at 17:6-10.

<sup>157</sup> *Id.* at 17, see Footnote 28.

<sup>158</sup> *Id.* at 17:10-11.

<sup>159</sup> Duvall, Exh. No. GND-4T at 62:6-8. The revised forecast lowered the Company’s deferral request to approximately \$2.4 million.

<sup>160</sup> WA, UE-140094 – PC (1-5) Confidential Attachment PC 2, Pacific Power’s 6<sup>th</sup> Supplemental Response.

<sup>161</sup> Mullins, Exh. No. BGM-1CT at 67:22-24.

<sup>162</sup> *Id.* at 61:7-8.



it produces no evidence to support its claim. If abnormal conditions did exist, the Company's hydro performance during the period did not suffer from them. In fact, Staff shows that the Company's expected hydro performance during 2014 will be *better than average*. This fact undermines any claim for extraordinary relief due to abnormal conditions.

**B. The Company's Hydro Tracker Design Ignores Commission Precedent**

87 If approved, the proposed Hydro Tracker would allow PacifiCorp dollar-for-dollar recovery of certain power costs related to a *single element* of its total NPC. As recently as the Company's last general rate case, the Commission gave clear direction to the Company on the appropriate design of a power cost recovery mechanism.<sup>163</sup> There the Commission concluded,

“[T]he Company's proposal in this case really is nothing more than a request for a *power cost tracker and true-up mechanism that will guarantee the Company full recovery of its power costs on a continuing basis*. We are not prepared to embrace such a mechanism and, therefore, reject PacifiCorp's proposed PCAM.”<sup>164</sup>

88 In this prior case, the Commission was responding to PacifiCorp's proposed PCAM which was designed without dead bands or sharing bands. But, the basic principle announced in the Commission's Order 05 is applicable here as well – power cost trackers that guarantee a company full recovery of power costs are not favored by the Commission. Although narrower in scope than the Company's previous PCAM, the Hydro Tracker is designed as a power cost tracker that will monetize the difference between forecasted hydro performance and actuals, and provide the Company *full* recovery of such costs on a continuing basis. These design elements have been rejected by the Commission in the past and should be rejected here.

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<sup>163</sup> Docket UE-130043, Order 05.

<sup>164</sup> *Id.* at ¶173.

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Much like PacifiCorp's rejected PCAM design, its Hydro Tracker seeks to recover ordinary variability in power costs. Thus shielding itself from the effects of weather, resulting hydro conditions, and changes in fuel costs.<sup>165</sup> As pointed out by Mr. Gomez, the Commission's Order 05 specifically rejected the inclusion of *normal* hydro variability in a power cost recovery mechanism.<sup>166</sup> Despite the clarity of the Commission's guidance, the Company again seeks identical but narrower relief through its Hydro Tracker. In fact, the normal hydro results reflected in the Hydro Tracker are already accounted for in the Company's power cost forecasts. The Company has no need to pursue these same dollars through its tracker mechanism.<sup>167</sup>

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Just to be clear, Staff is not opposed to a properly designed and inclusive mechanism to address the recovery of PacifiCorp's total NPC, including its hydro and renewable generators. It has proposed in this case a PCAM that would address the cost recovery issues raised by the Company via its Hydro Tracker proposal and RRTM.<sup>168</sup>

## VI. RENEWABLE RESOURCE TRACKING MECHANISM

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PacifiCorp's proposed Renewable Resource Tracking Mechanism (RRTM) would effectively separate cost recovery of its renewable resources (predominantly wind) from its Net Power Costs (NPC). The RRTM would multiply the output of its renewable resources by the difference between GRID's forecasted market price and the period market prices to determine the amount to be recovered from or credited back to ratepayers.<sup>169</sup>

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As proposed, the mechanism would hold PacifiCorp harmless from GRID's repeated failure to produce accurate forecasts of the actual value of its wind generation.<sup>170</sup> Further, the

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<sup>165</sup> Gomez, Exh. No. DCG-1CT at 17:17-20 and at 18:1-3.

<sup>166</sup> "Normal" is determined by the Company's long-term average of hydro results that "includes all extreme events" and are thus reflected in the Company's total power costs. See Gomez, Exh. No. DCG-1CT at 18:4-7.

<sup>167</sup> *Id* at 18:8-9.

<sup>168</sup> *Id* at 18:16-24.

<sup>169</sup> Duvall, Exh. No. GND-1CT at 38:6-18.

<sup>170</sup> Duvall, Exh. No. GND-1CT at 41, Table 7.

RRTM would function as a mini-PCAM that would give special cost recovery treatment to a small slice of the Company's generating fleet while ignoring the actual costs of its generating resources serving the WCA. As demonstrated by Staff, such special treatment is unwarranted and inconsistent with the PCAM design principles enunciated by the Commission in PacifiCorp's 2013 rate case.<sup>171</sup> For these reasons, the RRTM should be rejected.

**A. The RRTM is a Theoretical Construct Based on Company Forecasts that Bear No Relationship to the Company's Actual Power Costs.**

93 The Company's offers two reasons why the Commission should approve its RRTM proposal – the output variability of its wind generator fleet and its inability to recover the difference between its projected and actual value of its wind generator output.<sup>172</sup> Neither reason is compelling.

94 Specifically, PacifiCorp argues its new wind resources are intermittent, and as a result, volatility has been created in “the Company's NPC that would not exist without these resources.”<sup>173</sup> The Company misstates the issue. The intermittent nature of its wind resources is not the cause of any alleged volatility in its NPC. If such volatility exists, it is caused by the Company's own inability to accurately forecast market prices.

95 Staff's undisputed testimony clearly demonstrates that PacifiCorp has produced reasonably accurate forecasts of the production of its wind fleet. As shown by Mr. Twitchell, the Company's wind production forecasts over the period 2007-12 were within 10 percent of actual wind production for the period.<sup>174</sup> Mr. Mullins testified that the output of the Company's wind

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<sup>171</sup> Docket UE-130043, Order 05 at ¶170. *See also*, Twitchell Direct, Exh. No. JBT-1T at 9:13-22.

<sup>172</sup> Duvall, Exh. No. GND-1CT at 43:10-12.

<sup>173</sup> Duvall, Exh. No. GND-4T at 51:20 and 52:1-3.

<sup>174</sup> Twitchell, Exh. No. JBT-1T at 10:24-25. *See also*, Duvall, Exh. No. GND-1CT, at 41, Table 7 (comparing GRC Wind Generation Forecasts with Actual).

resources “remain relatively stable” with a year to year output deviation of approximately 6 percent.<sup>175</sup> This confined range of variability indicates that the Company has been reasonably successful at projecting the output of its wind facilities. It follows that the ability to reasonably forecast wind generator output should provide the Company a reasonable opportunity to properly manage these resources. Importantly, it fails to show that management of the wind fleet has led to *actual* unrecovered power costs.<sup>176</sup> Instead, PacifiCorp attempts to make its case by pointing to its own inability to accurately *forecast* future market prices.<sup>177</sup> Thus, the RRTM represents nothing more than a “theoretical construct” that in no way reflects actual costs incurred by the Company.<sup>178</sup> This is reason enough to reject the RRTM.

**B. Ratepayers Should Not Be Responsible for the Company’s Forecasting Errors.**

96 Staff’s unrebutted analysis shows that over 73 percent of the Company’s alleged under-recovery of wind variability costs were the direct result of the Company’s failure to accurately forecast period market prices. In fact, the Company’s period “market price projections were, on average, about 96 percent higher than actual market prices.”<sup>179</sup> Further, the Company’s poor history of accurately forecasting market prices was spread over “a period that lacked any large market shocks.”<sup>180</sup> Therefore, the Company’s failure to accurately forecast market prices cannot be blamed on market influences outside its control. The root of its problem rests solely with the Company’s price forecasting tools.

97 PacifiCorp offers no excuses for its forecasting errors and makes no representations that they can be avoided in the future. Rather than improving GRID’s forecasting tools, the Company

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<sup>175</sup> Mullins, Exh. No. BGM-1CT, at 54:14-17.

<sup>176</sup> The Company fails to support the RRTM with an accounting of *actual* costs incurred to manage its wind resources.

<sup>177</sup> Duvall, Exh. No. GND-ICT, at 41, Table 7 (comparing GRC Forecasted Market Prices with Actual).

<sup>178</sup> Twitchell, Exh. No. JBT-1T at 11:12-14.

<sup>179</sup> Twitchell, Exh. No. JBT-1T, at 11:1-2.

<sup>180</sup> *Id.* at 11:3.

seeks to foist upon ratepayers a hypothetical financial burden caused by its repeated forecasting failures. If the RRTM is adopted, the Company would lose all incentive to improve its forecasting. This is wrong and the Commission should not allow it.

**C. The RRTM is a Fundamentally Flawed PCAM**

98 The construct of the RRTM replicates the fundamental design of a PCAM. First, it would forecast power costs to set a “cost base.” The RRTM’s “cost base” would then be compared with end-of-period actual costs to determine whether PacifiCorp’s “costs” had been recovered. If not, a surcharge would be imposed on ratepayers. If actual costs were lower than forecasted, then ratepayers would receive a credit.<sup>181</sup> As proposed, the RRTM contains no dead bands or sharing bands. Therefore, both surcharges and credits would be subject to an annual dollar-for-dollar “true up” determined by the Commission.<sup>182</sup> While largely limited to wind resources, the RRTM would act just like a PCAM and should be subject to the same rules.<sup>183</sup>

99 The Commission has not approved a PCAM in any form that protects a Company from all power cost risks, including exposure to normal weather and market price variations.<sup>184</sup> PacifiCorp fully understands the Commission’s precedent in this regard, but ignores it. In its most recent rate case, it proposed a full PCAM that would have allowed recovery of all Net Power Costs (NPC), including the effects of normal weather and market fluctuations. In no uncertain terms, the Commission rejected its PCAM design.<sup>185</sup>

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<sup>181</sup> Twitchell, Exh. No. JBT-1T at 6:23-24 and 7:1-2.

<sup>182</sup> Duvall, Exh. No. GND-1CT at 38:6-10.

<sup>183</sup> Twitchell, Exh. No. JBT-1T at 6:23-24.

<sup>184</sup> Cf. Docket UE-011595, Fifth Supplemental Order.

<sup>185</sup> Docket UE-130043, Order 05 at ¶173.

The “appropriate balance” referred to by the Commission in Order 05 is achieved through properly designed dead bands and sharing bands.<sup>186</sup> These design features provide an incentive for PacifiCorp to effectively manage its power costs, in whole or in part.<sup>187</sup> While the Company may argue that its RRTM is not actually a PCAM, it must admit that it seeks recovery of a slice of its power costs through a mechanism that is indeed a “power cost tracker” guaranteeing full recovery of the targeted costs. In the context presented, the RRTM would cover the same ground as a PCAM – only a smaller share of it. As effectively explained by Mr. Twitchell, the “RRTM’s reduced scope does not mean that it is not a PCAM; rather the reduced scope makes it an improperly designed PCAM.”<sup>188</sup>

**D. A PCAM Should Include All the Company’s Power Costs and Not Just a Small Slice of its NPC.**

The Commission has never approved a power cost recovery mechanism that included only a portion of a company’s total power costs. The reason is simple. The financial performance of a company’s *entire* generation portfolio is what determines whether a company has under- or over-recovered its power costs. The performance of one generation sector is generally immaterial to final results of the whole portfolio’s performance.

The Company’s generation fleet is broadly diversified, and includes in order of dependency – coal, natural gas, hydropower and wind.<sup>189</sup> All of these resources carry some degree of use and therefore cost variability.<sup>190</sup> The Company’s GRID model forecasts its NPC

<sup>186</sup> Docket UE-050684, Order 04 ¶96.

<sup>187</sup> “Contrary to express Commission direction, and in contrast to the power cost adjustment mechanisms approved in other PacifiCorp jurisdictions, the Company’s proposal here includes neither dead bands nor sharing bands. These are critically important elements that provide an incentive for the Company to manage carefully its power costs and that protect ratepayers in the event of extraordinary power cost excursions that are beyond the Company’s ability to control, Docket UE-130043, Order 05 at ¶170.

<sup>188</sup> Twitchell, Exh. No. JBT-1T, at 7:2-4.

<sup>189</sup> Twitchell, Exh. No. JBT-1T at 12:5-8.

<sup>190</sup> *Id.* at 12:8-9.

based on expected loads and the availability of these generators to meet expected loads.<sup>191</sup> For example, the Company's cost to run its thermal resources will vary up and down based upon how often they are used and market prices for coal and natural gas.<sup>192</sup> If these generators are not physically or financially available, then the Company has the option of purchasing power on the market.<sup>193</sup> The important point is that PacifiCorp coordinates its generator fleet of generators and market purchases to meet contemporaneous demand and to respond to market conditions. Wind generators and other renewables are part of this fleet, and are likewise coordinated with PacifiCorp's other generators. They get no special treatment in the control room or when the Company forecasts its total NPC. Nor should they.

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The Company's NPC is based upon the total costs of its generation fleet and forecasted market costs. The RRTM or any other mechanism that seeks compensation for the performance of only one sector of generators "ignores the real possibility that the costs of its other generators may be lower than that expected over the period in question."<sup>194</sup> To this point, Mr. Twitchell succinctly stated:

By segregating wind resources for special cost treatment, the Company ignores the real chance that reduced costs in other areas of its generator portfolio could more than offset any difference between the wind energy costs determined by its NPC model and in-period actuals.<sup>195</sup>

Although expressed a bit differently, Mr. Mullins also testified that the Company's diverse portfolio is what matters, and the RRTM's attempt to isolate cost recovery of certain generators

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<sup>191</sup> *Id.* at 12:20-21.

<sup>192</sup> *Id.* at 12:10-11.

<sup>193</sup> *Id.* at 12:15-18.

<sup>194</sup> *Id.* at 13:3-4.

<sup>195</sup> *Id.* at 13:12-15.

“ignores the fact that [the Company’s] overall system is benefiting as a result of the diverse nature of all the resources in its portfolio.”<sup>196</sup>

104 In sum, the evidence presented by Staff and Boise Packaging clearly demonstrates that the RRTM’s focus on single characteristic resources is too narrow and fails to consider what really matters – the cost performance of the Company’s entire resource portfolio and market purchase activities. The hypothetical costs offered by the RRTM should be rejected in favor of a full PCAM as proposed by Mr. Gomez.

**E. PacifiCorp Cannot Rely on the Energy Independence Act to Save its RRTM**

105 PacifiCorp quotes RCW 19.285.050(2) of the Energy Independence Act (EIA) to support its RRTM.<sup>197</sup> Essentially, it implies that the EIA would mandate recovery of alleged costs covered by its RRTM. For reasons already expressed above, the flawed design of the RRTM would allow the Company to recover what amounts to fictional costs that are derived entirely from its failure to accurately forecast market prices.

106 In pertinent part, RCW 19.285.050(2) states: “An investor-owned utility is entitled to recover all *prudently incurred* costs associated with compliance with this chapter.” In plain words, the statute requires a showing that: the costs were actually incurred by the Company; and that such costs were incurred prudently. PacifiCorp cannot show that the RRTM would produce recoverable costs. As Staff demonstrates, the Company is seeking recovery of costs it has not actually incurred. Even assuming for the sake of argument these “costs” actually were incurred, the Company’s history of poor market price forecasts would make a prudence finding difficult to justify.

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<sup>196</sup> Mullins, Exh. No. BGM-1CT at 57:21-22 and 58:1-2.

<sup>197</sup> See Duvall, Exh. No. GND-1CT at 39:5-7.



107 Staff has effectively demonstrated that the Company's market price forecasting errors are the cause of the hypothetical "costs" sought to be recovered by the RRTM. The Company has made no promises to correct the problem in the future. Hence, the "costs" to be captured by the Company's RRTM represent nothing more than a hypothetical number and not costs actually "incurred". Without truly incurred costs, the EIA does not help PacifiCorp.

108 While prudence is the EIA's second "prong" leading to eligible resource cost recovery, prudence will not be an issue unless the RRTM is approved. Curiously, PacifiCorp's evidence supporting the RRTM does little more than point out its inability to accurately forecast period market prices. Such evidence speaks more to the Company's imprudence for failing to improve GRID's forecasting ability. It could have shown that it diligently acted to modify GRID to produce a more accurate forecasting tool, but it did not. It even failed to address GRID's ability to produce accurate market forecasts in the future. These are fatal errors.

#### **F. Conclusion**

109 The RRTM is a flawed mechanism that purports to recover costs incurred in the operation of PacifiCorp's renewable resources. In reality, the mechanism would only produce hypothetical "costs" as demonstrated by the Company's inability to accurately forecast market costs. Contrary to Commission precedent, the RRTM is designed as a "power cost tracker" that would guarantee full recovery of its targeted costs. This is another example of its flawed design. Finally, the mechanism is too narrow and ignores both the resource diversity on the Company's system and the total costs such diversity produces. In other words, actual costs over any period will fluctuate and it is the total portfolio costs that matter – not that of a single generation sector. The best mechanism to deal with the Company's NPC is a PCAM. The RRTM should be rejected.

## VII. RATE DESIGN

### A. Introduction

110 Rates should be designed to allow PacifiCorp a reasonable opportunity to earn its revenue  
requirement, to promote efficiency in the use of the service, and to distribute the Company's  
revenue requirement fairly and equitably among customers.<sup>198</sup> To accomplish these basic  
objectives, the Commission has enunciated certain factors that would inform its judgment when  
deciding the design of rates, including:

“acceptability of rate design to customers; elasticities of demand, or the variation  
of demand when prices change; perceptions of equity and fairness; rate stability  
over time; and overall economic circumstances within the region.”<sup>199</sup>

111 The Commission has also designed rates to accomplish particular objectives, such as the  
expansion of energy efficiency and decoupling.<sup>200</sup>

112 Staff's rate design proposal effectively balances these factors and objectives, and would  
expand energy efficiency through the adoption of a third rate block. Finally, it would provide  
PacifiCorp a reasonable opportunity to recover its costs.

113 Staff's rate design balances two fundamental objectives: providing PacifiCorp a more  
reliable opportunity to recover its costs and incenting customers to invest in higher levels of  
conservation. To achieve this balance, Staff's rate design increases the basic charge for  
residential customers.<sup>201</sup> With an increased monthly basic charge, the Company's cost recovery

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<sup>198</sup> *Bonbright, et al*, Principles of Public Utility Rates at 385.

<sup>199</sup> *Utilities & Transp. Comm'n v Puget Sound Power & Light Company*, Docket U-81-41 (March 12, 1982) at 24.  
*See also, Utilities & Transp. Comm'n v. Pacific Power & Light Company*, Docket U-86-02, 1986 WL 1299692  
(September 19, 1986) at 27.

<sup>200</sup> *In re Review of PURPA Standards in The Energy Independence and Security Act of 2007*, Docket U-090222 01,  
2009 WL 2983252 (September 14, 2009), at 5-8. *See also Utilities & Transp. Comm'n v. Avista Corporation*, Order  
5, UE-140188 and UG-140189 (consolidated), 2014 WL 6721270 (November 25, 2014).

<sup>201</sup> Twitchell, Exh. No. JBT-1T at 24:12-17.

is less dependent upon kilowatt-hour sales – thus reducing the Company’s motivation to increase sales. To incent customers to invest in conservation, Staff proposes to add a third (inclining block) rate tier that would place a higher revenue burden on the Company’s highest users of electricity.<sup>202</sup> When these two elements are coupled, Staff’s rate design produces benefits for the Company and its ratepayers.

**B. Staff’s Proposed Customer Charge Would Improve the Company’s Cost Recovery**

114 Staff’s rate design would increase a residential customer’s monthly basic charge from \$7.75 to \$13.<sup>203</sup> Staff determined this amount by including the costs associated with distribution transformers in the basic charge.<sup>204</sup> In general, basic charges (including the Company’s) only include costs that vary with the addition of another customer, such as service drops, meters, billing, etc.<sup>205</sup> Staff’s proposal to include transformers in the basic charge may be a diversion from current practice, but it is reasonable given the Company’s negligible customer growth. One can sensibly infer that a new transformer would not be needed to add a customer. In an effort to move beyond the elements already included in its basic charge, Staff has concluded that transformers are the next logical step.

115 As noted, a higher basic charge would allow PacifiCorp a better opportunity to recover its costs. In this proceeding, the Company represented that it has not achieved its Commission-authorized rate of return in recent years. However, there is a clear distinction between a company’s recovery of costs and its earnings.<sup>206</sup> But, assuming the veracity of the Company’s

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<sup>202</sup> *Id.* at 22:17-21. In addition, Staff’s third tier would incent further development of distributed generation on the Company’s system.

<sup>203</sup> *Id.* at 4:13.

<sup>204</sup> *Id.* at 26:18-20.

<sup>205</sup> Exh. No. GAW-1T at 20:4-5.

<sup>206</sup> TR, at 395:6-9. It goes without saying that the Commission does not *guarantee* that the Company will earn its allowed return on an annual basis. Further, a company’s actual return is dependent upon weather-affected sales, overall costs and the general management of the Company.

representation, Staff's rate design would improve the Company's cost recovery by moving a greater share of its monthly revenue away from the variability associated with kilowatt-hour sales. This alone should improve the Company's actual return.

116 Pacific Power is already in the midst of an era of declining load growth, in part due to the energy efficiency requirements of the Energy Independence Act.<sup>207</sup> In addition, federal environmental actions are expected to require PacifiCorp to accelerate its energy efficiency programs.<sup>208</sup> Staff's rate design should give the Company a reasonable opportunity to reach its revenue requirement even in an era of uncertain load.<sup>209</sup> Staff's increased basic charge is necessary to achieve this goal, and makes the Company's revenue less dependent on the amount of energy it sells. In turn, the higher basic charge would reduce risks that PacifiCorp faces as state and federal policies affect load growth.<sup>210</sup>

117 Curiously, PacifiCorp has not requested a decoupling mechanism in this case. The decoupling mechanisms recently approved by the Commission provide the affected utilities a guaranteed amount of revenue, regardless of actual retail sales.<sup>211</sup> In effect, a decoupling mechanism would provide it more certainty of cost recovery. Absent such a request, Staff elected to address the issue by increasing the residential basic charge, which all customers pay each month regardless of usage.<sup>212</sup> When compared with a decoupling mechanism, Staff's proposal offers improved certainty of recovery, but only for a portion of the Company's costs to serve a customer. The remainder would still be recovered via its kilowatt-hour sales. A

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<sup>207</sup> Twitchell, Exh. No. JBT-1T at 23:25 and at 24:4.

<sup>208</sup> *Id.* at 25:3-7.

<sup>209</sup> *Id.* at 23:18 and at 24:17.

<sup>210</sup> *Id.* at 41:3-8.

<sup>211</sup> Twitchell, Exh. No. JBT-1T at 24:5-11. *See* Dockets UE-140188 and UG-140189, Order 05

<sup>212</sup> *Id.* at 24:12-15.

decoupling mechanism offers PacifiCorp a more complete solution, but it has elected not to seek one. Staff's basic charge proposal is a step in the right direction.

**C. Staff's Third Tier Proposal Would Increase Energy Efficiency**

118 Staff's proposal to increase the basic charge would weaken the link between energy sales and revenue recovery, but not eliminate it. Staff goes a step further by proposing a third rate block for high-use customers. The new rate block would incent investment in energy efficiency by providing high-use customers a stronger and more effective price signal. In doing so, it would support multiple state policies that express strong support for increased investment in energy efficiency<sup>213</sup> and renewable energy generation.<sup>214</sup>

119 Specifically, Staff's rate design would add a new third block for customers using 1700 or more kilowatt-hours per month. The rate for each kilowatt-hour in this block would be 11.996 cents.<sup>215</sup> The new rate block would be priced about 2.1 cents higher than the Company's current second-block rate, and about 1.7 cents higher than the Company's proposed second-block rate.<sup>216</sup>

120 Staff's proposed third block addresses the concern raised by many parties that increasing the basic charge is a disincentive for end-use conservation, since it results in lower volumetric rates, thereby reducing the marginal cost of additional usage.<sup>217</sup> Staff believes the creation of a third and higher priced rate block would provide a more accurate and effective price signal to a majority of PacifiCorp's highest energy users. Thus, Staff would appropriately impose additional costs on customers whose usage imposes greater costs on the Company's system.<sup>218</sup>

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<sup>213</sup> RCW 19.285.020.

<sup>214</sup> RCW 80.60.005.

<sup>215</sup> Twitchell, Exh. No. JBT-1T at 27:5-10.

<sup>216</sup> Twitchell, Exh. No. JBT-4 at 25.

<sup>217</sup> *Id.* at 21:23 – 22:2; *see also*, Exh. No. MEF-1T at 10:17-20 and Exh. No. CME-1T 22 4-7.

<sup>218</sup> Twitchell, Exh. No. JBT-1T at 27:16-22.

121 While PacifiCorp argued that its current, two-block rate structure already sends a strong price signal to customers, the evidence shows it does not.<sup>219</sup> The customer usage survey completed by PacifiCorp during the course of this case and used in its rebuttal testimony clearly shows that customers are neither recognizing nor responding to any price signal created by the Company's current rate structure.<sup>220</sup> In pursuing the state's policy to encourage energy efficiency and distributed generation, it is therefore appropriate to create a stronger price signal that customers will be more likely to perceive.

122 Staff's analysis demonstrates that its rate design could achieve an additional 7,660 MWh of energy conservation each year as customers respond to its third-block price signal.<sup>221</sup> In rebuttal testimony, PacifiCorp argues that Staff over-projected these potential savings by failing to account for the possibility of increased usage among customers who would receive a bill decrease under Staff's proposal.<sup>222</sup> However, the Company's own data demonstrates otherwise. Even if second block customers respond to the lower rate by increasing their usage, conservation in the third block would outweigh by approximately 300 percent any increased usage in the second block, resulting in net savings of about 5,000 MWh.<sup>223</sup>

123 PacifiCorp also attempts to demonstrate that its proposed rate design would generate more conservation than Staff's proposal, but the analysis is based on the flawed assumption that customers using less than 850 kWh per month would respond to the price signal in the same manner that customers with higher monthly usage.<sup>224</sup> To the contrary, these low-use customers

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<sup>219</sup> Twitchell, Exh. No. JRS-1T at 24:19-20.

<sup>220</sup> Exh. No. JRS-13T at 46:3-7.

<sup>221</sup> Twitchell, Exh. No. JBT-1T at 33:8-11.

<sup>222</sup> Exh. No. JRS-13T at 38:9-11.

<sup>223</sup> Exh. No. JRS-21.

<sup>224</sup> *Id.*

simply do not have enough discretionary consumption to respond to a price signal in any meaningful way.<sup>225</sup> For this reason, any analysis of how a price signal would affect customer behavior should omit that group.<sup>226</sup> When that group is omitted, even the Company's analysis shows that Staff's proposed price signal would generate *more* conservation.<sup>227</sup> Staff's proposal would also appropriately send the price signal to high-use customers, whose usage imposes greater costs on the Company's system; whereas, the Company's proposal would attempt to extract additional efficiency from customers that are already relatively efficient.

124 In sum, Staff has effectively demonstrated that its proposed three-block rate design is superior to PacifiCorp's rate design in creating a price signal that promotes energy efficiency and renewable energy investment.

**D. The Majority of the Company's Customers Would Benefit from Staff's Rate Design**

125 Should the Commission adopt Staff's rate design, the average customer's monthly bill would be reduced by approximately \$3.00.<sup>228</sup> This is a material decrease that benefits the majority of PacifiCorp's customers and ensures that its costs are being spread in a fair and equitable manner.

126 As expressed above, Staff's proposal to increase the basic charge has the effect of moving some fixed costs out of the volumetric rate. As a result, volumetric rates are reduced.<sup>229</sup> For the average customer using 1,300 kilowatt-hours, this interaction results in an overall bill reduction of \$3.04, as the lower volumetric rates more than offset the increased basic charge.<sup>230</sup>

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<sup>225</sup> Twitchell, Exh. No. JBT-1T at 28:10-13. See also Exh. No. CME-9T at 2:4-7.

<sup>226</sup> Twitchell, Exh. No. JBT-1T at 28:10-13.

<sup>227</sup> Exh. No. JRS-21.

<sup>228</sup> Twitchell, Exh. No. JBT-1T at 29:9-10.

<sup>229</sup> TR. at 649:14-15.

<sup>230</sup> Twitchell, Exh. No. JBT-1T at 29:9-12.

As Staff witness Twitchell explained in the hearing, a customer's bill is like a pie – the basic charge represents one piece and the volumetric blocks represent the other pieces. So, changing the size of a given slice doesn't necessarily change the size of the pie.<sup>231</sup> Under Staff's proposal, the whole pie (customer bill) would get smaller for the average customer. This result is a significant benefit to most customers – a benefit not provided under the Company's rate design. Once fully understood, the customers would accept Staff's rate design and likely find it preferable to the Company's alternative. Rate stability (rate shock) is only an issue so long as customers fail to grasp the actual relationship between the basic charge and their volumetric rate. The actual bill should be the real test for rate stability – not the customers' misperception of the basic charge's relationship to the total bill. Because Staff's proposal would reduce the bill for most customers, it easily passes the test.

Staff's proposal will not benefit all customers. It will likely result in higher bills for the smallest and largest users. As set forth above, bills will increase for high-use customers, but again, this is an appropriate allocation of rising costs, as these customers impose greater costs on the Company's system.<sup>232</sup> Furthermore, the basic charge increase will increase the bill for customers that do not use enough energy to realize the offsetting benefit of lower volumetric rates. However, Staff believes this is an appropriate and entirely supportable result. Under the current rate design, which recovers a larger share of fixed costs in volumetric rates, low-usage customers are not fully contributing to their share of PacifiCorp's fixed-cost recovery.<sup>233</sup> Staff's rate design would therefore result in a fairer and more equitable spread of revenue recovery within the residential class.

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<sup>231</sup> TR. at 615:3-8.

<sup>232</sup> Twitchell, Exh. No. JBT-1T at 27:16-22.

<sup>233</sup> TR. at 617:15-19.



## E. Conclusion

129 Taken in tandem, Staff's rate design would address the objectives set forth by the Commission. The core of Staff's proposed rate design is the increased basic charge and the resulting improvement in the Company's cost recovery, *coupled* with the creation of a third block that would create a strong incentive for customers to be efficient in their energy usage.

130 As described above, Staff's proposal moves some of the fixed costs that are currently collected in volumetric rates into the basic charge.<sup>234</sup> By reducing the amount of fixed costs that are recovered in volumetric rates, the Company is less dependent on selling electricity to recover its costs and has some degree of protection as customers use less electricity.<sup>235</sup> Staff's core proposals (the increased basic charge and the third rate block) are mutually dependent, and account for the tradeoffs necessary to balance two opposing policies. For, if the basic charge were to increase without the creation of a third block, then the price signal to support efficiency and distributed generation would be diluted. Similarly, the creation of a third block, absent an increase in the basic charge, could further exacerbate the Company's cost recovery challenges as customers respond to the price signal by using less energy. Since the two proposals are mutually dependent, it is necessary to consider their net effect when evaluating customer impacts.

131 Staff has effectively demonstrated that its rate design would provide benefits to the Company and customers. It also supports the Commission's objective to increase energy efficiency by using higher costs in the third block to trigger demand elasticity.

132 Staff's rate design is best for all ratepayers. For some with higher bills, Staff has shown why this result is both equitable and would prevent within-class subsidization. Staff's design also provides rate stability to the residential class by making a necessary change to the basic

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<sup>234</sup> TR, at 649:11-13.

<sup>235</sup> Twitchell, Exh. No. JBT-1T page 41, at 3-8.

charge/volumetric rate relationship. In fact, the majority of customers will experience a monthly bill decrease under Staff's design – hardly a cause for calls of rate shock. All in all, it is time for a change in how rates are designed. The Company and its ratepayers will be better off for it.

## IX. ACCOUNTING ADJUSTMENTS

### A. Adjustment 4.7, Insurance Expense

#### 1. Fundamental Principles

133 The Commission sets out to establish rates that are fair, just, reasonable, and sufficient.<sup>236</sup>

The Commission generally relies on historical data to ensure prospective rates will cover a company's legitimate expenses.<sup>237</sup> Rolling averages are a common regulatory tool used to estimate those expenses that experience fluctuations from year-to-year. The goal of a rolling average is to embed a fair and typical expense level in prospective rates.

#### 2. Issue

134 PacifiCorp replaces its per books insurance expense with the six-year average of annual insurance expenses.<sup>238</sup> Staff does not object to an averaging calculation but proposes to remove the 2012 insurance expense of \$30.8 million and replace it with the next-most-recent insurance expense of approximately \$10.1 million.<sup>239</sup> The Company acknowledges the extraordinary nature of its 2012 insurance expense and attributes the increase to, "increased reserves required for certain fires, an oil spill, personal injury claims, and other injuries and damages claims that occurred in 2012."<sup>240</sup>

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<sup>236</sup> RCW 80.28.020.

<sup>237</sup> See *Utilities & Transp. Comm'n v. Avista Corporation, dba Avista Utilities*, Docket UE-090134, Order 10 (Final Order) at 19, ¶ 41 (December 22, 2009).

<sup>238</sup> Siores, Exh. No. NCS-1T p. 18:1. The Company proposes to use the most recent six years of insurance expenses for calculating the average.

<sup>239</sup> Ball, Exh. No. JLB-1T p. 14:1-3.

<sup>240</sup> Ball, Exh. No. JLB-3 (PacifiCorp's response to Public Counsel Data Request No. 78). See also Siores, Exh. No. NCS-10T at 8:7-8 ("the 2012 expense level represents a higher level of expense...").

### 3. Staff Recommendation

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The 2012 insurance expense is a statistical outlier that should not be included in a six-year rolling average to project fair and reasonable insurance expenses into the rate year. The 2012 expense of \$30.8 million is more than 10 times the 2011 insurance expense and over three times the \$10 million expense in 2007, which was the next highest insurance expense PacifiCorp incurred over the relevant period.<sup>241</sup> The record simply does not demonstrate that the underlying events that caused the dramatic increase in 2012 insurance expenses are sufficiently likely to reoccur in the rate year or recur on a regular basis approximately every six years. As a result, inclusion of such expenses in a six-year rolling average is not fair or reasonable. The statistical anomaly would abnormally skew the average and not reflect a typical expense level most likely to occur during the rate year.

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PacifiCorp's primary argument is that a rolling average should, by definition, include both high and low years.<sup>242</sup> As Mr. Ball explains, however, the Company ignores the length of the rolling average used for insurance expense in this case, which is only six years, and the disproportionate impact 2012's insurance expense would have on rates.<sup>243</sup> PacifiCorp's proposal to include such an extraordinary expense in its calculation is not fair or reasonable and would likely result in an inappropriate cost recovery during the rate year. As a result, the Company's position violates the Commission's fundamental goal to set rates to reflect expenses most likely to be incurred in the rate year. The Commission should reject PacifiCorp's recommended adjustment, and adopt Staff's proposal outlined in the testimony of Mr. Ball.

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<sup>241</sup> Ball, Exh. No. JLB-1T at 14:8-10.

<sup>242</sup> See Siores, Exh. No. NCS-10T at 8:6-18.

<sup>243</sup> Ball, Exh. No. JLB-1T at 14.

## B. Adjustment 4.13, IHS Global Insight Escalation

### 1. Fundamental Principles

137 The Commission sets rates on the basis of a modified historical test year.<sup>244</sup> The Commission allows forward looking, pro forma adjustments provided those adjustments are sufficiently known and measurable.<sup>245</sup>

### 2. Issue

138 The Company proposes to project its non-labor and non-power cost operations and maintenance (“O&M”) expenses using the IHS Global Insight Indices. Staff recommends the Commission reject PacifiCorp’s proposed adjustment.

### 3. Staff Recommendation

139 As outlined in Mr. Ball’s testimony, the Company’s proposal circumvents Washington’s policy to base rates on an historical test year.<sup>246</sup> Mr. Ball also expresses concerns regarding the consistency of the Company’s escalation factors.<sup>247</sup> Most importantly, Mr. Ball succinctly notes that IHS Indices do not specifically relate to PacifiCorp’s operations in its Washington state service territories.<sup>248</sup> The Company’s testimony also acknowledges that the IHS indices are industry-wide, which necessarily supports Staff’s testimony that the IHS indices are not specific to PacifiCorp or its service territory.<sup>249</sup>

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<sup>244</sup> See Docket UE-090134, Order 10 at 19-22.

<sup>245</sup> Docket UE-090134, Order 10 at 21, ¶ 45. See also WAC 480-07-510(3)(e)(iii).

<sup>246</sup> Ball, Exh. No. JLB-1T at 16:1-4 and p. 17:11-21.

<sup>247</sup> Ball, Exh. No. JLB-1T at 18:2-7.

<sup>248</sup> Ball, Exh. No. JLB-1T at 16:14-22 (emphasizing that attrition relies on the company’s actual operations), and at 19:1.

<sup>249</sup> See Dalley, Exh. No. RBD-3T p. 12:20 – 13:6 (discussing IHS as a “national forecasting company” (emphasis added) and explaining that the available indices reflect the utility industry generally). Confidential Exh. No. RBD-5C includes an additional description of the relevant IHS indices, further demonstrating that the IHS indices are not based on PacifiCorp and its Washington service territory.

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Given the absence of any direct connection between the IHS indices and PacifiCorp's operations in Washington, the Company's proposed adjustment does not reflect any specific, known and measurable costs incurred serving Washington ratepayers. PacifiCorp simply has not demonstrated in this proceeding that the IHS Indices accurately reflect the Company's operations in Washington State. Therefore, PacifiCorp's proposal fails to meet any reasonable interpretation of the known and measurable standard.

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The Company's rebuttal testimony acknowledges that Staff, Public Counsel, and Boise reject the proposed adjustment on the basis of Commission precedent.<sup>250</sup> The Company's principal argument appears to be that its claims of historical under-recovery should persuade the Commission to largely ignore regulatory principles and allow "discrete" adjustments that would increase the Company's opportunity to earn its authorized return.<sup>251</sup> As the Company seems to acknowledge, its proposal is not supported in law or Commission precedent.<sup>252</sup> The Commission should reject PacifiCorp's proposed Adjustment 4.13 to include the IHS Global Insight Index Escalation and adopt Staff's recommendation for continued use of the historical test year and the known and measurable standard.

### **C. Merwin Fish Collector**

#### **1. Fundamental Principles**

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A regulated company should be allowed the opportunity to recover prudent costs.<sup>253</sup> The Commission has also expressed policy concerns over frequent accounting petitions for rate base

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<sup>250</sup> See Dalley, Exh. No. RBD-3T at 12:9.

<sup>251</sup> Dalley, Exh. No. RBD-3T at 12:9-17.

<sup>252</sup> Dalley, Exh. No. RBD-3T at 12:9-17

<sup>253</sup> See RCW 80.28.020.

additions.<sup>254</sup> Only Staff's recommendation balances these relevant policy concerns. As a result, the Commission should adopt Staff's recommendation as outlined in the testimony of Mr. Jason Ball.<sup>255</sup>

## 2. Background and Issue

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The Commission previously rejected PacifiCorp's request for recovery of costs associated with the Merwin Fish Collector ("Merwin Project") in Docket UE-130043.<sup>256</sup> The Merwin Project was then placed in service in March 2014.<sup>257</sup> PacifiCorp subsequently petitioned the Commission in Docket UE-140617 to allow either: 1) recovery of costs through a separate tariff rider, or 2) an accounting petition to defer those costs.<sup>258</sup> The Commission rejected the tariff rider but granted the accounting petition for a deferral ("the Merwin deferral").<sup>259</sup> The Commission then consolidated Docket UE-140617 into the present general rate proceeding, Docket UE-140762.<sup>260</sup> As Mr. Ball's testimony explains, the Merwin Project is now both prudent and used and useful for ratepayers;<sup>261</sup> however, the Parties to the present proceeding disagree on treatment of the Merwin deferral granted by the Commission in Docket UE-140617.

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Staff does not recommend disallowance of any portion of the Merwin Project. No party objects to including the Merwin Project in rate base going forward. The only issue in dispute is the Company's requested extraordinary relief to defer costs and revenue requirement associated

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<sup>254</sup> Ball, Exh. No. JLB-1T at 27:13-14 (citing *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket No. UE-060266, Order 08 at ¶ 47 and footnote 33 (January 5, 2007)).

<sup>255</sup> Ball, Exh. No. JLB-1T at 25-29.

<sup>256</sup> Ball, Exh. No. JLB-1T at 21:1-2.

<sup>257</sup> Ball, Exh. No. JLB-1T at 21:7.

<sup>258</sup> Ball, Exh. No. JLB-1T at 21:10-15.

<sup>259</sup> Ball, Exh. No. JLB-1T at 21:19. See also *Utilities & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140617, Order 01 (Order 3 of Docket UE-140762) (May 29, 2014).

<sup>260</sup> *Utilities & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Order 03 (Order 01 of Docket UE-140617) (May 29, 2014).

<sup>261</sup> Ball, Exh. No. JLB-1T at 20-25.

with the Merwin project that occurred before and during the present proceeding. PacifiCorp recommends the Commission allow recovery of the entire Merwin deferral.<sup>262</sup> Boise and Public Counsel both recommend rejecting the Merwin deferral in its entirety.<sup>263</sup> Staff recognizes the Company's need for cost recovery as well as the Commission's policy preference to avoid incenting inter-period rate base additions.<sup>264</sup>

### 3. Staff Recommendation

145 Staff proposes the Commission allow the Company to recover the O&M and depreciation included in the deferral but exclude pre-tax return on rate base.<sup>265</sup> Staff's recommendation provides shareholders with cost recovery while removing the primary return incentive for frequent accounting petitions. Staff's position is not unprecedented. As Mr. Ball explains in his testimony, Staff's recommendation is consistent with a past case where the Commission endorsed a no-interest deferral for a similar project.<sup>266</sup> Of the various Parties to this proceeding, only Staff's position balances competing policy concerns and recognizes the prior Commission precedent.

146 In the alternative, if the Commissions agrees with the Company and grants the full amount of the deferral, Staff recommends that the Commission not allow recovery of the additional interest currently accruing on the deferral.<sup>267</sup> Because the Merwin deferral is for the full revenue requirement, the Company's proposal already includes the return on and of the plant

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<sup>262</sup> Dalley, Exh. No. RBD-3T at 13-14; Siores, Exh. No. NCS-10T at 24.

<sup>263</sup> Ramas, Exh. No. DMR-1CT at 45; Mullins, Exh. No. BGM-1CT at 68.

<sup>264</sup> Ball, Exh. No. JLB-1T at 27:13-14 (citing Docket No. UE-060266, Order 08 at ¶ 47, ¶ 51 and footnote 33.

<sup>265</sup> Ball, Exh. No. JLB-1T at 25:13-19.

<sup>266</sup> Ball, Exh. No. JLB-1T at 28:14-19. Mr. Ball's footnote 36 on p. 28 of his testimony cites specifically to *Petition of Avista Corp. for an Accounting Order to Defer Costs Related to Improving Dissolved Oxygen Levels in Lake Spokane*, Docket UE-131576, Order 01 (September 6, 2013).

<sup>267</sup> Ball, Exh. No. JLB-1T at 29.

investment for the Merwin Project. Additional interest would provide a direct incentive for companies to seek accounting petitions for all potential ratebase additions.

#### **D. Plant Additions**

##### **1. Issue**

147 PacifiCorp initially proposed Adjustment 8.4 to include plant additions greater than \$250,000 that would be placed in service between January 1, 2014 and March 31, 2015.<sup>268</sup> In the rebuttal testimony of Ms. Siores, the Company updated its proposed adjustment for major plant additions to reflect projects that are currently in service (as of September 30, 2014) or expected to be placed into service prior to the rate effective date of March 31, 2015.<sup>269</sup> The Company then proposes to update its adjustment to reflect actual plant in service as of March 31, 2015.<sup>270</sup>

##### **2. Staff's Recommendation**

148 Staff recommends the Commission allow PacifiCorp to update its plant additions to reflect actual plant in service.<sup>271</sup> Staff's position relies on recent Commission precedent in Docket UE-130043, in which the Commission allowed plant additions on the basis of updated figures the Company provided in its rebuttal testimony.<sup>272</sup> Staff's recommendation also balances the Commission's policy preference for an historical test year with allowing the Company a fair opportunity to earn an authorized return in the rate year. The Company's updated proposal filed on rebuttal is substantively identical to Staff's recommendation.

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<sup>268</sup> Siores, Exh. No. NCS-1T at 26:8-11.

<sup>269</sup> Siores, Exh. No. NCS-10T at 15:10-20.

<sup>270</sup> Siores, Exh. No. NCS-10T at 15:5-7.

<sup>271</sup> Erdahl, Exh. No. BAE-1T at 8:5-8.

<sup>272</sup> See Docket UE-130043, Order 05 at 74 ¶ 187 and at 79-80.



## E. Colstrip Deferral

### 1. Background and Issue

149 PacifiCorp proposes to recover Colstrip and Depreciation deferrals associated with Dockets UE-131384 and UE-132350 through a separate tariff rider. Staff recommends the Commission allow the Company to recover costs associated with both the Colstrip and Depreciation deferrals, excluding interest, through general rates.

### 2. Staff's Recommendation

150 Staff's recommendation excludes interest because of the type of expenses associated with the Colstrip and Depreciation deferrals. Ms. Erdahl's testimony explains that Colstrip largely represents the purchase of power during a Colstrip plant outage.<sup>273</sup> Ms. Erdahl further points out that power costs typically do not earn interest and would be recovered over a period of time. Thus, Staff recommends the Commission exclude interest from the deferrals and allow recovery in general rates over the course of the rate year.

151 Alternatively, should the Commission determine interest on the Colstrip and Depreciation deferrals is appropriate, Ms. Erdahl recommends the Commission remove revenue-sensitive taxes. The Company's proposal currently calculates interest on revenue sensitive taxes rather than only the amount of the relevant deferrals.

## X. CONCLUSION

152 This case presents numerous contested issues for the Commission to decide. On these matters, it can be assured that Staff's recommendations adhere to recent Commission precedent and fundamental regulatory principles. To illustrate, Staff's cost of capital reflects current market conditions, and its capital structure appropriately balances safety and economy. As to

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<sup>273</sup> Erdahl, Exh. No. BAE-1T at 11:11-22.

power costs, Staff's PCAM is properly designed and comports with clear Commission precedent by including sharing and dead bands. Regarding interstate cost allocation, Staff supports the WCA in its current form, and strongly recommends that the Commission reject the Company's second attempt to impose the costs of its Oregon and California QFs on Washington ratepayers. Washington ratepayers should not pay the additional costs associated with Oregon and California policy decisions. The Commission is not obligated to set rates for the convenience of the Company's regional business plan.

153           Staff's rate design is consistent with goals and objectives set forth by the Commission. It is fundamentally fair, provides the Company a reasonable opportunity to recover its costs, and would result in bill decreases for a majority of customers. Furthermore, it effectively incents investment in energy efficiency and distributed generation. For these reasons, Staff's rate design is best for customers and PacifiCorp.

154           PacifiCorp's deferral petitions have been thoroughly analyzed to ensure results that are fair, just, reasonable, and sufficient. For the reasons given herein, Staff is opposed to the Company's Hydro Tracker and RRTM mechanisms. These proposals are flawed in design and not sufficiently supported by the evidence presented by the Company. However, Staff does support recovery of the Company's Colstrip deferral and partial recovery of its investments in the Merwin hydro facility.

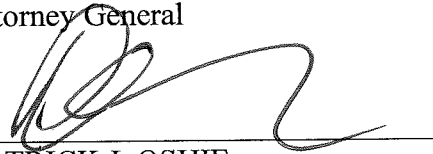
155           Staff's accounting issues are straightforward in concept and result. PacifiCorp's IHS-based expense adjustment bears no relationship to the Company's actual costs of doing business in Washington and should be rejected. Staff does however, accept the Company's proposal to allow into rates facilities placed into service before final rates go into effect.

Staff's numerous recommendations in this proceeding are consistent with Washington policies, embrace sound ratemaking practices, allow the Company a sufficient return, and ensure that PacifiCorp's rates are fair, just and reasonable. They should be adopted.

Dated this 22<sup>nd</sup> day of January 2015.

Respectfully submitted,

ROBERT W. FERGUSON  
Attorney General



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PATRICK J. OSHIE  
Assistant Attorney General  
JENNIFER CAMERON-RULKOWSKI  
Assistant Attorney General  
BRETT P. SHEARER  
Assistant Attorney General  
Counsel for Washington Utilities and  
Transportation Commission Staff