

September 11, 2015

***VIA ELECTRONIC FILING  
AND OVERNIGHT DELIVERY***


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**RE: Docket UE-144160—Pacific Power & Light Company's Initial Brief**

Pacific Power & Light Company, a division of PacifiCorp (PacifiCorp or Company), submits for filing its initial brief in this proceeding.

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Sincerely,

  
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Enclosures

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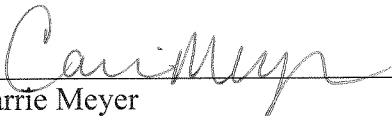
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**BEFORE THE WASHINGTON  
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

Respondent.

**DOCKET UE-144160**

**PACIFIC POWER & LIGHT COMPANY'S INITIAL BRIEF**

**September 11, 2015**

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## I. BACKGROUND

1 Pacific Power & Light Company, a division of PacifiCorp (PacifiCorp or Company) publishes standard avoided cost prices in its Schedule 37. Schedule 37 applies to qualifying facility (QF) projects with a nameplate capacity of up to 2 megawatts. As required by the Washington Utilities and Transportation Commission (Commission), Schedule 37 prices are offered to QFs as fixed prices over a five-year term.<sup>1</sup> On December 29, 2014, the Company filed Advice 14-08, which updated published Schedule 37 prices to reflect updated resource requirements and other inputs to the avoided cost calculation, such as wholesale prices for natural gas and electricity.

2 The Company's filing originally proposed two changes to Schedule 37. First, the Company included a charge to reflect costs associated with integrating intermittent QF generation.<sup>2</sup> Second, the Company eliminated payments for capacity based on the costs of simple cycle combustion turbine (SCCT), a change that is consistent with the resource sufficiency period identified in the Company's 2013 Integrated Resource Plan (IRP) Update.<sup>3</sup> Following an open meeting on February 12, 2015, the Commission suspended the Company's tariff revisions and opened an investigation into the proposed integration charge and other aspects of the filing.<sup>4</sup>

3 After discussions with Commission staff (Staff) and the Renewable Energy Coalition (REC), the Company withdrew the proposed variable generation integration charges.<sup>5</sup> The Company continues to support eliminating SCCT costs in Schedule 37 prices during the resource sufficiency period. In order to maintain the ratepayer indifference objective mandated by the Public Utility Regulatory Policies Act of 1978

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<sup>1</sup> Prices are provided in Schedule 37 for a period of 10 years, but only available for a fixed-price purchase agreement of 5 years or less.

<sup>2</sup> Declaration of Brian S. Dickman ("Dickman Dec.") at ¶ 4 (June 12, 2015).

<sup>3</sup> *Id.*

<sup>4</sup> *WUTC v. Pacific Power & Light Co.*, Docket No. UE-144160, Order 01 (Feb. 12, 2015).

<sup>5</sup> The Company, however, reserved the right to include variable generation integration charges in its avoided costs prices at a later date in a different docket. Upon final resolution of the issues in this docket, or at such time as the Commission orders, the Company will revise its proposed Schedule 37 tariff sheets to reflect the withdrawal of the integration charges.

(PURPA), deferred capacity costs must be included in avoided costs in a manner consistent with the Company's resource procurement plans identified in its IRP. Specifically, the fixed costs of a displaced generating unit should only be included in avoided costs when (and to the extent) those costs can actually be avoided by the Company. If such costs continue to be reflected in Schedule 37 rates when they cannot actually be avoided by the Company, retail customers will improperly pay prices for QF power that are higher than the Company's avoided cost.

4           Staff and REC oppose the Company's proposed changes, while Boise White Paper, LLC, (Boise) supports them. Staff's and REC's proposals conflict with PURPA's customer indifference standard because they would require the Company to either pay QFs twice for capacity or to pay for capacity the Company will not avoid. These errors are not minor. Despite the discretion afforded to state regulatory bodies to establish methodologies for determining avoided cost, PURPA explicitly forbids methodologies that, on their face, result in payments to QFs that exceed a utility's actual avoided costs.<sup>6</sup> Most importantly, Staff and REC's proposals would unnecessarily harm Washington customers.

## II. DISCUSSION

5           PURPA requires a utility to purchase a QF's energy and capacity at rates equal to the utility's avoided cost. "Avoided cost" is "the incremental cost to the electric utility of electric energy or capacity or both, which but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."<sup>7</sup> In other words, the calculation of avoided cost is essentially a "but for" inquiry: but for the addition of QFs,

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<sup>6</sup> See, e.g., *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at 62,080 (1995) ("*So. Cal. Edison*") overruled on other grounds, *Cal Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010) (overturning avoided cost methodology proposed by California Public Utilities Commission because the methodology itself would result in payments to QFs that exceed avoided cost).

<sup>7</sup> 18 C.F.R. § 292.101(b)(6). FERC has identified QF characteristics "affecting rates for purchase" to be considered when determining avoided costs. See 18 C.F.R. § 292.304(e).



how much would the Company otherwise have paid for energy and capacity needed to reliably serve load?

6 While the calculation of avoided cost is an area in which states enjoy a great deal of discretion, that discretion does have limits. PURPA allows a state to set rates *below* avoided cost in certain circumstances,<sup>8</sup> but it forbids a state from setting rates with a methodology that results in rates that *exceed* a utility's avoided cost.<sup>9</sup> In other words, rates for QF purchases should equal the cost of the resources the Company would incur to serve load absent the QF purchases. The methodology used to calculate avoided costs may not be structured or designed in a way that yields an avoided cost higher than the "but-for" inquiry would yield.<sup>10</sup>

7 As state regulators across the country have observed time and time again, while PURPA aimed to encourage the production of cogeneration and small power production, Congress intended that retail customers would be insulated from financial harm while that goal was pursued.<sup>11</sup> FERC has affirmed this principle, noting that Congress intended

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<sup>8</sup>See 18 C.F.R. §292.304(b)(3): "A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production."

<sup>9</sup>Under PURPA, it is improper to, "provide for a rate which exceeds the incremental cost to the electric utility of alternative energy." 16 U.S.C. § 824a-3(b) (Rates for purchases by electric utilities): "The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."

FERC regulations echo this requirement. 18 C.F.R. §292.304(a) states as follows:

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

<sup>10</sup> See, e.g., 16 U.S.C. § 824a-3(b).

<sup>11</sup> See, e.g., *WUTC v. v. Wash. Water Power Co.*, Cause No. U-86-119, 83 P.U.R. 4th 364 at \*26 (Apr. 23, 1987) ("Consistent with the goals of PURPA, ratepayers and utilities should remain indifferent to whether power is purchased from qualifying facilities or from other sources. In achieving this objective, the

to “make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.”<sup>12</sup> Even PURPA’s legislative history makes clear that PURPA was not intended to subsidize QFs—it simply allowed them to sell power at the cost of other, alternative resources.<sup>13</sup> Staff’s and REC’s recommendations in this docket conflict with PURPA’s definition of avoided cost and with its goal of customer indifference and would improperly inflate PacifiCorp’s avoided cost.

**A. The Company Appropriately Based Its Schedule 37 Avoided-Cost Calculations on the Costs the Company Will Avoid Due to QF Purchases.**

8 The Company’s proposed Schedule 37 avoided cost calculations accurately capture the costs the Company would avoid due to QF purchases, no less and no more. The calculations are separated into two periods: a resource sufficiency period, and a resource deficiency period. The Company’s deficiency period begins in 2027 at the earliest—the date the Company plans to make its next major thermal resource acquisition under its 2013 IRP Update.<sup>14</sup> The resource deficiency/sufficiency demarcation allows the Company to properly match its avoided cost calculations with the Company’s actual resource acquisition plans. If the Company becomes resource deficient—that is, it requires the acquisition of a new base load thermal generator—avoided costs would be equal to the fixed and variable costs of the combined cycle combustion turbine (CCCT) it intends to acquire per its IRP. This is because, during a deficiency period, QFs would (in theory) help the Company defer the CCCT, making the appropriate avoided cost the avoided variable (energy) and fixed (capacity) costs of that specific, avoided resource.<sup>15</sup>

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Commission will use the best forecasts and best assumptions possible to arrive at accurate estimates of avoided costs.”)

<sup>12</sup> *So. Cal. Edison*, 71 FERC ¶ 61,269 at 62,080 (emphasis added).

<sup>13</sup> *See* Conference Report on PURPA, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 97-98 (“The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.”)

<sup>14</sup> Dickman Dec. at ¶ 7.

<sup>15</sup> *Id.*

9 By contrast, avoided costs during the sufficiency period are based not on the costs of additional new thermal resources, but on the results of differential runs using the Company's production cost model, Generation and Regulation Initiative Decision Tools (GRID).<sup>16</sup> According to the 2013 IRP Update, the Company is not resource deficient until at least 2027, which is beyond the published fixed-price horizon for PacifiCorp's Washington Schedule 37.<sup>17</sup> Therefore, avoided cost prices for a QF that are determined and fixed between 2015 to 2026 fall entirely within PacifiCorp's resource sufficiency period.

10 To calculate avoided costs during this period, the Company uses two GRID runs simulating the dispatch of resources in the Company's west control area: one scenario without any new resources, and one with an additional generic 50 average megawatt resource (included at zero cost).<sup>18</sup> The difference in net power costs between the two runs is the avoided cost. As PacifiCorp declarant Brian Dickman explains, including zero-cost energy in the GRID model causes a redispach of the system in which the highest incremental cost resources are displaced to accommodate the additional energy. The resources displaced are a combination of reduced wholesale market purchases (or increased market sales in some hours) and reduced generation from the Company's dispatchable thermal units. The cost difference between the two runs yields the Company's avoided cost; that is, the differential reveals the costs the Company would incur "but for" the addition of the new QF resources.<sup>19</sup>

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<sup>16</sup> *Id.* at ¶ 9.

<sup>17</sup> For current prices, the deficiency period did not occur until 2024 and, therefore, the effective prices reflect only sufficiency period avoided costs. The Company's 2013 IRP Update showed that the Company's next deferrable thermal capacity resource is a 423 MW CCCT in 2027. Dickman Dec. at ¶ 10. In the Company's 2015 IRP (Docket No. UE-140546) filed March 31, 2015, the next major thermal generator acquisition is not projected to be until 2028. Table 8.7 of the 2015 IRP. *See* Rebuttal Declaration of Brian S. Dickman ("Dickman Rebuttal Dec.") at fn. 9 (July 24, 2015).

<sup>18</sup> Dickman Dec. at ¶ 9.

<sup>19</sup> *Id.*

**1. QF Purchases Would Not Allow the Company to Avoid the Fixed Costs of an SCCT.**

11 Specific capacity payments have historically been included in the Company's Schedule 37 during time periods when the Company is projected to be resource sufficient. These capacity payments have been based on the fixed costs of a SCCT for three months each year.<sup>20</sup> The Company is moving to eliminate these payments because including them in avoided cost calculations during a sufficiency period falsely implies that the Company would incur the costs of a SCCT to meet capacity needs during periods of peak load. This construct, however, is false. The Company does not incur such costs when it is resource sufficient, and it would therefore be impossible for a QF to help the Company avoid them. As the Company's 2013 IRP Update indicates, the Company does not need to acquire a thermal generating resource until at least 2027. For this reason, SCCT capacity costs have been eliminated from Schedule 37. Consistent with PURPA's customer indifference standard, PacifiCorp's proposed avoided costs include only the costs that would actually be avoided by the addition of QF output.

**2. QF Purchases Would Displace (and Therefore Allow the Company to Avoid) Front Office Transactions; These Transactions Therefore Provide the Proper Basis for Avoided Cost Pricing.**

12 As the Company's IRP indicates, the Company will, in fact, rely on front office transactions (FOTs), which are representative of short-term firm wholesale market purchases, to balance the Company's capacity needs.<sup>21</sup> Short-term firm market purchases contribute to meeting PacifiCorp's firm obligations to serve load, inclusive of a 13 percent planning reserve margin, which ensures the Company has sufficient capacity to maintain reliability at a reasonable cost. Paying a QF for the avoided cost of FOTs, then, is the equivalent of paying a QF the costs the Company would incur to purchase energy

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<sup>20</sup> In other words, one-fourth of the fixed cost of an SCCT was included as a capacity payment annually. *Id.* at ¶ 10.

<sup>21</sup> Dickman Dec. at ¶ 11. For example, in the 2013 IRP Update FOTs rise to over 1,400 megawatts in 2026, the last year before a new major thermal resource is added. *Id.*

and capacity “but for” the addition of a QF. This is the textbook definition of avoided cost.

13 FERC recognized as much in its landmark Order No. 69. In that order, FERC discussed how a QF should be compensated for its contribution to a utility’s capacity needs. FERC concluded that, if a utility was not planning to acquire a new generation resource for some time, but in the meantime was relying on firm market purchases to meet its energy and capacity needs, the appropriate compensation for a QF prior to acquisition of the new resource was simply the *cost of the avoided firm market purchase*. As FERC explained:

In order to provide capacity value to an electric utility a qualifying facility need not necessarily agree to provide power for the life of the plant. A utility’s generation expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into a bulk power purchase arrangement with another utility. *The rate for such a purchase should thus be based on the price at which such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.*<sup>22</sup>

The Company’s calculation of avoided cost is consistent with this principle.

14 The Company calculates its avoided cost using the Company’s GRID model to quantify the costs of resources that would actually be avoided due to the addition of QFs. In this case, the resources actually avoided are primarily FOTs. Using the Company’s GRID model to calculate avoided costs during the sufficiency period captures the impact of QF generation displacing short-term market transactions, and therefore captures the Company’s actual avoided cost. As Mr. Dickman explains, the modeled avoided costs during the sufficiency period are based on approximately 99 percent market transactions and approximately 1 percent reduced thermal generation.

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<sup>22</sup> Order No. 69, *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Pub. Util. Regulatory Policies Act of 1978*, 45 Fed. Reg. 12,214, 12,226 (1980) (“Order No. 69”).

**GRID Model Avoided Cost Breakdown**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Market transactions (avoided purchases/increased sales)	99.09%	98.87%	98.76%	98.64%	98.62%	98.57%	98.51%	98.73%	98.70%	98.84%
Reduced thermal dispatch	0.91%	1.13%	1.24%	1.36%	1.38%	1.43%	1.50%	1.28%	1.30%	1.16%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The displacement of market transactions during the sufficiency period (1) properly reflects displacement of the resource the Company actually intends to use to meet capacity needs per the IRP, and (2) therefore provides a proper basis for avoided cost under PURPA’s definition of that term.<sup>23</sup>

**3. The Company Is Willing to Modify the Proposed Schedule 37 Rate Design to Include On- and Off-Peak Pricing.**

15 The Company’s proposed Washington Schedule 37 prices are equal to the avoided costs from the GRID model, including the displacement of wholesale market transactions, expressed as a flat \$/MWh rate. The previously included capacity payment based on a SCCT is set to \$0.<sup>24</sup> Under this structure, a QF is paid a fixed price for all energy generated, regardless of the time of generation, as the price is an annual average

<sup>23</sup> Other states served by the Company have recently addressed, or are currently reviewing, the calculation of the Company’s sufficiency period avoided cost prices. For example, the Wyoming Public Service Commission approved PacifiCorp’s Schedule 37 update in an August 2015 order. *See In re Application of Rocky Mountain Power for Authority to Revise Schedule 37 Standard Rates for Purchases of Power from Qualifying Facilities*, Wyoming PSC Docket No. 20000-458-EA-14, Order (record number 14021) (Aug. 26, 2015). In Utah, the Company proposed to eliminate SCCT costs from the sufficiency period in a May 7, 2014 Schedule 37 update. The Utah Public Service Commission initially adopted the Company’s proposal, but reversed its decision and directed the Company to provide additional evidence supporting the change in its next Schedule 37 update. The Company subsequently filed a petition for review of final agency action with the Utah Supreme Court, which review is ongoing. *See Office of Consumer Servs. v. Pub. Serv. Comm’n of Utah*, Case No. 20150066-CA (Utah Ct. App.). On April 30, 2015, the Company filed its latest Utah Schedule 37 update, again excluding the SCCT costs from the sufficiency period. In Oregon, Schedule 37 prices are set equal to projected wholesale market prices during the sufficiency period with no additional imputation of SCCT fixed costs. *E.g., In re Pub. Util. Comm’n of Oregon Staff’s Investigation Relating to Elec. Util. Purchases from Qualifying Facilities*, Oregon PUC Docket No. UM 1129, Order No. 11-505 at 4 (Dec. 13, 2011). The determination of sufficiency period avoided cost prices is currently under review by the Public Utility Commission of Oregon in docket UM 1610, but Oregon Commission Staff agrees with PacifiCorp that paying a QF the cost of avoided market transactions during the sufficiency period appropriately compensates the QF for capacity. *See In re Pub. Util. Comm’n of Oregon Staff Investigation Into Qualifying Facility Contracting and Pricing*, Oregon PUC Docket No. UM 1610, Testimony of Brittany Andrus, Staff Exhibit 500 at 30-31 (May 22, 2015).

<sup>24</sup> Dickman Dec. at ¶ 16.

that includes periods of higher avoided costs (during periods of peak demand) and lower avoided costs during off-peak.<sup>25</sup> As noted by Mr. Dickman, the Company is willing to revise its proposed Schedule 37 prices to differentiate the energy payment into on- and off-peak periods, with prices during on-peak periods set higher to reflect the increased value of QF generation during those time periods.<sup>26</sup> Basing the on- and off- peak differential on the spread between on- and off-peak Mid-Columbia market prices produces results shown in the table below, which are also compared to the Company’s initial filing (excluding integration costs).<sup>27</sup>

Year	Washington Schedule 37				
	Differentiated Prices (\$/MWh) Mid-C Spread		Dec 2014 Filing (\$/MWh)	Difference \$/MWh	
	HLH	LLH	Base Load	HLH	LLH
2015	\$36.36	\$27.52	\$32.48	\$3.88	(\$4.96)
2016	\$38.31	\$28.99	\$34.12	\$4.19	(\$5.13)
2017	\$41.00	\$30.56	\$36.40	\$4.60	(\$5.84)
2018	\$44.07	\$32.79	\$39.10	\$4.97	(\$6.31)
2019	\$47.13	\$34.76	\$41.70	\$5.43	(\$6.94)
2020	\$50.09	\$36.82	\$44.14	\$5.95	(\$7.32)
2021	\$51.97	\$39.86	\$46.64	\$5.33	(\$6.78)
2022	\$53.69	\$42.96	\$48.97	\$4.72	(\$6.01)
2023	\$56.27	\$45.02	\$51.30	\$4.97	(\$6.28)
2024	\$58.56	\$47.12	\$53.39	\$5.17	(\$6.27)

#### 4. Conclusion.

16 Under FERC’s PURPA regulations, avoided cost is defined as the cost a utility will *actually avoid* as a result of QF purchases. While the determination of avoided cost can be complicated, in this instance it is fairly straightforward: the FOTs that form the basis for PacifiCorp’s proposed Schedule 37 avoided costs are the transactions PacifiCorp would actually avoid as the result of QF purchases.

<sup>25</sup> *Id.*

<sup>26</sup> *Id.*

<sup>27</sup> *Id.*

**B. The Alternative Proposals Offered by Other Parties Misstate PacifiCorp's Avoided Cost.**

**1. General Concerns Regarding Other Parties' Avoided Cost Recommendations.**

17 Staff's and REC's recommendations regarding various avoided-cost modifications or adders are based on erroneous premises, or simply run afoul of the "but for" avoided-cost examination required by PURPA. Most significantly, as discussed above, Schedule 37 avoided costs should not include the capacity costs of a SCCT when the Company cannot (and would not) actually avoid such costs.

18 FERC has made clear that states are free to encourage renewable generation in any number of ways, in addition to their implementation of PURPA. They may, for example, establish renewable portfolio standards, offer tax incentives, order utilities to build renewable facilities, or pursue any number of other incentives or mandates for renewable generation.<sup>28</sup> With respect to these incentive programs, states are free to set power prices or cost-recovery requirements in any manner they wish. PURPA, however, is a federal statute, and it has specific statutory limits. What states may *not* do, FERC explained, is encourage renewable generation through PURPA by setting avoided costs at rates that *exceed* a utility's actual avoided costs.<sup>29</sup> Forcing utilities to pay inflated avoided costs as a means of encouraging renewable generation violates one of the fundamental principles underlying PURPA.

19 REC appears to argue, in direct violation of this principle, that the Commission should increase PacifiCorp's Schedule 37 avoided costs simply as a matter of policy, pointing to the fact that other states or utilities may, in some instances, offer more favorable terms and conditions to QFs than PacifiCorp does in Washington.<sup>30</sup> First, as noted above, an avoided cost methodology may not result in QF rates for purchase that

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<sup>28</sup> See, e.g., *So. Cal. Edison*, 71 FERC ¶ 61,269, 62,079-62,080.

<sup>29</sup> *Id.*

<sup>30</sup> See, e.g., Declaration of John R. Lowe ("Lowe Dec.") at ¶ 11 (July 13, 2015).



exceed a utility's avoided cost.<sup>31</sup> Therefore, inflating avoided cost based on REC's apparent state-by-state comparability policy principle, rather than the cost of a utility's avoided resources, is improper and violates PURPA.

20           Second, so long as avoided cost is calculated appropriately, a differential in avoided cost pricing among utilities (or among states), does not suggest a PURPA violation. To the contrary, FERC's PURPA regulations assume that avoided costs will differ among utilities.<sup>32</sup> FERC even provides a means for a QF to wheel its power from one interconnected utility to another utility, if the second utility provides more attractive terms.<sup>33</sup> Thus, the fact that PacifiCorp's avoided cost may be lower than another utility's does not justify the imposition of artificial adders or costs to PacifiCorp's Schedule 37 prices simply as a matter of policy preference; rather, such actions are expressly forbidden by PURPA. The inquiry before the Commission, PacifiCorp would submit, is simply whether PacifiCorp's Schedule 37 accurately represents the Company's avoided costs, not whether PacifiCorp's avoided cost provides QFs the best deal in town.

**2.       The Company's Sufficiency/Deficiency Demarcation Is Relevant for Purposes of Identifying the Resource Being Avoided.**

21           PacifiCorp is also concerned with Staff's conclusions about whether and when the Company should make capacity payments and/or include capacity adders. In particular, as discussed in more detail below, the Company asserts: (1) the sufficiency/deficiency demarcation is relevant for purposes of identifying when the Company actually needs to purchase new capacity; (2) the IRP appropriately does not make blanket assumptions regarding QF renewal for purposes of resource deferral determinations; and (3) if the Commission determines that some form of capacity adder is appropriate during the sufficiency period, the adder should reflect the current Commission-approved construct.

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<sup>31</sup> See, e.g., 16 U.S.C. § 824a-3(b).

<sup>32</sup> See, e.g., Order No. 69, 45 Fed. Reg. at 12,226.

<sup>33</sup> See, e.g., 18 C.F.R. § 292.303(d).

**a. The Company’s Sufficiency/Deficiency Demarcation Is Relevant.**

22 Staff witness Jeremy Twitchell argues that PacifiCorp is currently in a resource deficient position because it acquires capacity via FOTs and that QF purchases allow PacifiCorp to avoid FOT purchases.<sup>34</sup> He therefore asserts that QFs should therefore be paid a capacity payment. While PacifiCorp agrees that FOTs are necessary to address shortfalls of capacity, not just energy, this does not mean the costs of a SCCT—or any other separate capacity adder—should be included in the Company’s Schedule 37 when no SCCT is actually being avoided or deferred. During the sufficiency period, as opposed to the deficiency period, the resources that will be avoided or deferred as a result of QF purchases are actually FOTs.

23 PacifiCorp’s IRP does identify FOTs as necessary to address capacity shortfalls. As a matter of practice, the Company has for many years referred to the period before acquisition of the next major thermal resource as the “resource sufficiency period” or “the short run” despite the recognized reliance on market transactions in its IRPs.<sup>35</sup> In the 2013 IRP Update, on which the current filing is based, the Company relies on FOTs to balance the Company’s capacity needs before the next major thermal resource acquisition in 2027. FOTs are representative of short-term wholesale market purchases, and reliance on FOTs represents the least-cost, lowest-risk option for acquiring near-term capacity before the next major thermal resource acquisition.<sup>36</sup>

24 Staff erroneously states that the Company fails to provide “any value for capacity in its avoided cost rate.”<sup>37</sup> In fact, the market transactions that would be avoided as a result of QF purchases represent the cost of energy *and capacity* that the Company will incur before the acquisition of the next thermal resource.<sup>38</sup>

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<sup>34</sup> Declaration of Jeremy Twitchell (“Twitchell Dec.”) at ¶¶ 16-17 (July 14, 2015).

<sup>35</sup> Dickman Rebuttal Dec. at ¶ 6.

<sup>36</sup> *Id.*

<sup>37</sup> Twitchell Dec. at ¶ 14.

<sup>38</sup> Dickman Rebuttal Dec. at ¶¶ 7-8.

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Staff also argues that “[a]ny QF that enters Pacific Power’s system prior to a future market purchase will reduce the amount of capacity that the Company needs to acquire, and must be compensated appropriately for those avoided capacity costs.”<sup>39</sup> Based on that observation, Staff concludes that the fixed costs of the next CCCT in the Company’s IRP should be included in avoided cost prices beginning in 2015. This conclusion misapprehends the nature of FOT market purchases. FOTs are the lowest-cost, least-risk option for addressing near-term capacity shortages. FOTs are *firm products*, and the sellers *supply all necessary reserves*.<sup>40</sup> This means that when PacifiCorp purchases those products, it is also paying for reserves and all other services needed to hold and deliver the power purchased. As noted previously, FERC has acknowledged this scenario, explaining that when a utility intends to acquire a new resource in the future, but relies for some period of time on firm market transactions instead, the utility’s avoided cost is the cost of the avoided firm market transactions.<sup>41</sup>

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This makes sense under the avoided cost construct. For example, a 100 MW firm market purchase requires the seller to deliver 100 MW to PacifiCorp, regardless of circumstances, so the seller must provide sufficient reserves to ensure that it has that supply available to provide to PacifiCorp.<sup>42</sup> This, in turn, means that PacifiCorp is freed up from holding additional reserves on its 100 MW firm front office purchase; the price of the seller’s capacity is embedded in the price of the market transaction.<sup>43</sup> It is therefore false to say that an avoided cost based on deferred FOTs fails to compensate a

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<sup>39</sup> Twitchell Dec. at ¶ 19.

<sup>40</sup> Dickman Rebuttal Dec. at ¶ 8. By way of example, any firm transmission arrangements that are used to deliver such short-term, firm power purchases and arranged for pursuant to a transmission provider’s Federal Energy Regulatory Commission-approved Open Access Transmission Tariff (“OATT”) will require either the self-supply or purchase of certain ancillary services necessary to support that firm delivery. For instance, the *pro forma* OATT includes the following ancillary services: (i) Scheduling, System Control and Dispatch; (ii) Reactive Supply and Voltage Control from Generation or Other Sources; (iii) Regulation and Frequency Response; (iv) Energy Imbalance; (v) Operating Reserve – Spinning; (vi) Operating Reserve – Supplemental; and (vii) Generator Imbalance. *See, e.g., FERC Pro Forma OATT, Section 3, Ancillary Services.*

<sup>41</sup> *See* Order No. 69, 45 Fed. Reg. at 12,226.

<sup>42</sup> Dickman Rebuttal Dec. at ¶ 8.

<sup>43</sup> *Id.*

QF for capacity; the price of capacity is simply embedded in the price of the avoided FOT itself.

27 As FERC stated in Order No. 69, “[i]f [a QF] demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit *or the purchase of firm power from another utility*, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs.”<sup>44</sup> This quotation recognizes that avoided capacity may be in the form of a new generating facility, or in the form of firm purchases from other providers. Here, the avoided capacity resource is the avoidance of firm FOT purchases, purchases identified in the Company’s IRP as the lowest-cost, least-risk option for addressing capacity shortages. Including a thermal resource capacity adder on top of the price of avoided market transactions would over-compensate QFs and would squarely conflict with PURPA’s customer indifference standard.<sup>45</sup>

**b. The Company’s IRP Appropriately Makes No Blanket Assumptions About QF Contract Renewal.**

28 Staff also argues that, although QF contracts in Washington are limited to a five-year fixed-price term, they help to defer thermal resources identified for 2027 and beyond.<sup>46</sup> This argument is predicated on Staff’s incorrect assumption that in the IRP all QFs are assumed to renew their contracts upon expiration. That is not the case. PacifiCorp’s IRP does not make a blanket assumption that all existing QFs will renew; instead, it only assumes that certain small QFs are extended through the end of the planning period while contracts with other QFs will expire according to their terms.<sup>47</sup>

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<sup>44</sup> Order No. 69, 45 Fed. Reg. at 12,225 (emphasis added).

<sup>45</sup> *So. Cal. Edison*, 71 FERC ¶ 61,269 at 62,080 (In enacting PURPA, “[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.”)

<sup>46</sup> See Twitchell Dec. at ¶¶ 20-21.

<sup>47</sup> Dickman Rebuttal Dec. at ¶ 10 (citing to PacifiCorp 2015 IRP, Volume 1 at 75).

**c. Any Capacity Adders Should Reflect the Commission-Approved Construct.**

29 If the Commission determines that some form of capacity adder is appropriate during the sufficiency period, the adder should reflect the current Commission-approved construct. Currently, PacifiCorp's capacity adder is limited to one-fourth of the SCCT cost, representing peak periods of demand during three out of twelve months annually.<sup>48</sup> Staff has proposed including a capacity adder across all months. This would conflict with PacifiCorp's resource procurement plans, where FOTs are required only during the third-quarter peak period. Including a capacity adder during the remaining nine months of the year would incorrectly inflate avoided cost prices in conflict with PURPA's customer indifference standard.<sup>49</sup> Significantly, under Staff's proposal, the Company's Washington customers would be required to pay QFs the cost of avoided market purchases *and* the full fixed cost of a new CCCT from the beginning of the QF contract, even though the next CCCT acquisition is not planned until 2027 at the earliest.<sup>50</sup>

30 Staff calculated example payments to a 2 MW QF generator under various annual capacity factor assumptions, using the Company's current rate, proposed rate, and Staff's proposed rate. Based on Table 2 in his declaration, Mr. Twitchell concluded that Staff's additional capacity costs made only a small difference on an annual basis. The impact of Staff's proposal is an increase in annual avoided cost payments to a 2 MW QF ranging from over \$32,000 to \$98,000 annually. Over a five-year contract the difference ranges

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<sup>48</sup> See Dickman Rebuttal Dec. at ¶ 11. In the Company's 2015 IRP, existing QF contracts with a combined name plate capacity of only approximately 122 MW were assumed to be renewed before the next thermal resource acquisition in 2028. Most of these QFs are hydro projects that have existed for many years. Furthermore, the magnitude of their generation at the time of peak load is less than the name plate capacity of the generators and is not significant enough to have a material impact on the timing of the next major thermal resource acquisition in the IRP. One-fourth of the costs of a SCCT were included to represent peak periods of demand during three out of twelve months annually. REC's argument implies that the avoided costs should only reflect costs the Company will incur, but REC fails to acknowledge that the Company currently has no plans to acquire any SCCT at all.

<sup>49</sup> Dickman Rebuttal Dec. at ¶ 11.

<sup>50</sup> *Id.* The Company's recently-filed 2015 IRP delayed the next CCCT acquisition until 2028. Like Staff, REC is critical of the fact that current avoided cost rates only include three months' worth of the fixed costs of a SCCT. Lowe Dec. at ¶ 30.

from over \$163,000 to approximately \$490,000. A corrected Table 2 is provided below.<sup>51</sup>

<b>Capacity Factor</b>	<b>Current Rate</b>	<b>Company Proposal</b>	<b>Staff Proposal</b>
90%	\$585,557	\$538,004	\$636,932
50%	\$325,309	\$298,891	\$353,851
30%	\$195,186	\$179,335	\$212,311

**3. The Renewable Portfolio Standard (RPS) Incremental Cost Method, While Useful for RPS Purposes, Is Inappropriate for Calculating Avoided Cost.**

31 Staff argues that, rather than use its PURPA-specific avoided cost methodology to calculate avoided cost, the Company should instead use Washington’s method for calculating incremental costs in the context of RPS reporting to calculate avoided cost. Staff believes that the “incremental cost methodology is ideally suited to this issue, because the avoided cost calculation in Schedule 37 and the incremental cost calculation in the RPS report have a common purpose: to determine the avoided costs that the utility would have faced but for the regulatory requirement to purchase a different resource.”<sup>52</sup> In making this determination, Staff assumes that the methodology for determining avoided cost for the utility should be the same regardless of whether the purpose is to calculate the correct price for QF power or to report on RPS requirements.<sup>53</sup> This is an overly simplistic comparison of two very different concepts.

32 The Washington Energy Independence Act contains an RPS provision that requires electric utilities with 25,000 or more customers to obtain a certain percentage of their electricity from new renewable resources, beginning in 2012.<sup>54</sup> The Commission is

<sup>51</sup> Staff’s initial policy declaration erroneously calculated the impact of Staff’s proposal. Staff conceded this error and filed an erratum to Mr. Twitchell’s declaration so recognizing. *See* Errata to Declaration of Jeremy Twitchell (July 24, 2015).

<sup>52</sup> Twitchell Dec. at ¶ 32.

<sup>53</sup> *See id.*

<sup>54</sup> *See, e.g.,* RCW 19.285.040.

authorized to enforce these standards with respect to investor-owned utilities.<sup>55</sup> As part of these enforcement duties, the Commission has issued rules requiring subject utilities to report their compliance with the RPS by utilizing a uniform methodology that calculates the incremental cost of RPS compliance.<sup>56</sup> This assists Staff in its prudency review of the utilities' renewable resource and certificate management.<sup>57</sup> Importantly, this uniform methodology was developed intentionally to be used by all of the utilities—essentially allowing for the Commission to do an “apples to apples” comparison on whether the utilities' decisions to purchase renewable energy and/or credits are reasonable as compared with a hypothetically similar traditional power purchase.

33           This methodology, however, does not comport with the factors utilized to determine avoided costs under PURPA. As noted previously, FERC defines avoided costs as “the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.”<sup>58</sup> Under PURPA, then, a utility is required to purchase energy from QFs at the utility's own avoided cost—whatever that cost may actually be.

34           The determination of avoided cost therefore must be determined in light of the individual factors affecting each utility's own procurement plans. The RPS incremental cost calculation compares the cost of an RPS eligible resource to a non-eligible resource (*i.e.*, a CCCT) available at the time of the eligible resource's acquisition, but the incremental cost calculation is simplified (and goes fundamentally awry for purposes of avoided cost calculations) in that it compares an eligible resource to a CCCT assumed to be procured at the same time and in the same size increment as the eligible resource, whether or not the utility *would actually have procured* a CCCT in the absence of the

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<sup>55</sup> RCW 19.285.060(6).

<sup>56</sup> See *e.g.*, *In re Amending, Adopting, and Repealing Rules in WAC 480109 Relating to the Energy Independence Act*, Docket UE-131723, General Order R-578 at P 110 (Mar. 12, 2015).

<sup>57</sup> *Id.*

<sup>58</sup> 18 C.F.R. § 292.101(b)(6)

eligible resource. In other words, the RPS method has nothing to do with an individual utility's actual avoided cost.

35 This type of oversimplification is inappropriate for determining the price to be paid to QFs on a specific utility's system, at a specific point in time, under FERC's avoided cost regulations. When calculating the costs that can be avoided due to the addition of a QF, it is imperative to account for the utility's current resource procurement plans and the timing of actual, planned resource additions. Retail customers should not be required to pay a QF the cost of a CCCT in 2015 when the utility would otherwise not incur such costs until 2027 at the earliest.

**4. Any Adjustment for Market Risk or Additional Market Liquidity Analysis Would Be Inappropriate and Unnecessary.**

36 Staff and REC make the following suggestions related to certain market factors: (1) PacifiCorp should attempt to quantify avoided market risks in its next avoided cost update; and (2) PacifiCorp should analyze whether there will be sufficient market liquidity to enter into the market purchases planned in its IRP. The Commission should disregard these suggestions for the reasons discussed below.

37 With regard to the first issue, Staff suggests that purchases from QFs mitigate risk associated with market purchases, and recommends that PacifiCorp quantify avoided market risks (*i.e.*, a "market risk premium") as part of its next avoided cost update.<sup>59</sup> Staff's position is built on a faulty premise that QF purchases eliminate market risks.

First, as the Commission has long recognized, fixed-price PURPA contracts may create financial risk for utilities, rather than mitigate risk. To that end, the Commission has stated, for example:

Acquiring a long-term contract for power at a reasonable levelized rate is certainly attractive, but the Commission knows that there are risks to such a purchase. There is a risk that the power will not be needed. There is a risk that the power will be needed but the seller will fail to perform. There

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<sup>59</sup> Twitchell Dec. at ¶¶ 25-30.



is a risk that the future projected avoided costs will be lower than we had assumed. There is also the troubling element of burdening today's customers with a "levelized" rate which is higher than the utility's current costs so that different customers 30 years from now can buy power at rates below cost. All of these risks and concerns demand that regulators err, if at all, on the side of reducing the present cost to ratepayers. If the error factor is small there should be little risk that reasonable opportunities for economical PURPA resources will be lost. This type of balancing is very much in keeping with the least cost planning initiative which this Commission has taken.<sup>60</sup>

38           These concerns still ring true today. For instance, market prices are in a period of sustained decline, due in significant part to historically low natural gas prices.<sup>61</sup> When market prices are dropping, fixed price avoided cost contracts (even those with limited five-year terms) expose PacifiCorp's customers to financial risk, as the QF purchases get locked in at above-market rates.<sup>62</sup> Staff witness Mr. David C. Gomez recognized this risk in his testimony in Docket UE-130043 when discussing the recent downward trend in avoided cost prices driven in part by lower market prices for natural gas. Mr. Gomez stated, "While this kind of price risk would also be present in any contract with a Washington QF, the risk impact is offset by the smaller size and output of the project and the shorter term lengths of the purchase agreements, as directed by Commission policy."<sup>63</sup>

39           Second, fixed-price QF contracts are not appropriate hedging mechanisms. A power or natural gas hedge must provide three components to be effective: (1) a predetermined quantity; (2) a predetermined time the product will be received; and (3) a predetermined price.<sup>64</sup> These components allow a utility to, among other things, manage hedges carefully in order to limit customer exposure to price risk, market liquidity and other risk considerations noted above. However, unlike an appropriate hedging mechanism, QF contracts – which provide only a predetermined price and are not

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<sup>60</sup> *WUTC v. v. Wash. Water Power Co.*, 83 P.U.R. 4th 364 at \*27.

<sup>61</sup> Dickman Rebuttal Dec. at ¶ 17.

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

<sup>63</sup> Docket UE-130043, Exhibit No. DCG-1CT, Testimony of David C. Gomez, page 13 lines 4-7.

<sup>64</sup> Dickman Rebuttal Dec. at ¶ 18.

necessarily tied to a resource need – are essentially unlimited hedges outside the Company’s control.<sup>65</sup> Additionally, QF resources are not without risk because their output is difficult to predict and their generation output is largely out of a utility’s control. For these reasons, the Commission should disregard Staff’s suggestion that PacifiCorp attempt to quantify avoided market risks, as it is based on a faulty presumption that PURPA contracts mitigate financial risk for utilities.

40           With regard to the second issue, REC incorrectly claims the Company has not conducted an analysis to determine if there will be sufficient market liquidity to enter into the market purchases planned in its IRP and states broadly that the Northwest Power and Conservation Council estimates an overall Northwest market shortfall. However, REC overlooks that in its 2013 IRP, the Company explains that it developed assumptions around the quantities of available FOTs considering historical operational data, institutional experience with transactions at the market hubs, and an assessment of expected physical delivery constraints and *market liquidity* and depth.<sup>66</sup> In its 2015 IRP the Company states: “PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, *market liquidity* and market depth, and with consideration of regional resource supply.”<sup>67</sup>

41           Furthermore, REC’s statements about the Northwest Power and Conservation Council’s assessment only tell a partial story. Indeed, those estimations indicate that, even without accounting for generation additions already planned for the region, the power supply in the Pacific Northwest is expected to be adequate through 2020, which is beyond the five-year term over which avoided cost prices are available.<sup>68</sup> For these reasons, the Commission should reject REC’s suggestions that PacifiCorp perform

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<sup>65</sup> *Id.*

<sup>66</sup> PacifiCorp 2013 IRP, Volume 1 at 155 (emphasis added).

<sup>67</sup> PacifiCorp 2015 IRP, Volume 1 at 129 (emphasis added). In addition, Appendix J of the 2015 IRP contains the Company’s Western Resource Adequacy Evaluation.

<sup>68</sup> Dickman Rebuttal Dec. at ¶ 19.

additional analysis regarding whether there will be sufficient market liquidity to enter into the market purchases planned in its IRP.

**5. Capacity Payments Should Not Be Guaranteed to QFs in Perpetuity.**

42 REC argues that a renewing QF should receive a capacity payment since the capacity that it provides has already been included in the utility's IRP load resource balance.<sup>69</sup> REC's proposal is a thinly veiled attempt at lengthening the availability of fixed avoided cost prices beyond the five years allowed by the Company's Washington tariff.<sup>70</sup> The Company recommends the Commission reject this proposal.

43 A utility's avoided costs are not static, and for this reason, it is logical that avoided cost prices need to be updated to account for changes in market and system conditions, including changes in a utility's capacity needs over time.<sup>71</sup> As avoided cost prices are updated and QFs seek new contracts, the most current avoided cost price information should be applied to the new contract, consistent with the customer indifference standard under PURPA. Staff recognized this when Mr. Twitchell stated, "Washington's use of a five-year term for the standard offer tariff benefits the Company and ratepayers by ensuring that avoided cost rates accurately reflect current market conditions."<sup>72</sup>

44 Guaranteeing a capacity payment to renewing QFs would be harmful to customers. Given the typical contracting and hedging horizons for energy contracts in the utility industry, which are commonly limited to less than 36 months, it is rare for a utility to voluntarily enter into a longer-term fixed-price energy contract (even for a five-year term) without a specified energy resource need due to concerns about price risk, market liquidity, prudence challenges, and other risk considerations.<sup>73</sup> Guaranteeing a

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<sup>69</sup> Lowe Dec. at ¶ 28.

<sup>70</sup> Dickman Rebuttal Dec. at ¶ 20.

<sup>71</sup> *Id.* at ¶ 21.

<sup>72</sup> Twitchell Dec. at ¶ 40.

<sup>73</sup> Dickman Rebuttal Dec. at ¶ 22.

capacity payment to renewing QFs as REC argues magnifies the risk and potential harm to customers by providing fixed avoided cost prices for excessive time periods. The combined effect of REC's proposals in this case is to pay a QF the fixed cost of a thermal resource from the beginning of the QF purchase in perpetuity, regardless of the Company's resource procurement plans. A QF seeking a new contract upon expiration of an existing contract should be treated the same as other QFs and avoided cost prices should reflect the utility's then-current energy and capacity needs at the time of renewal.<sup>74</sup>

**6. Any Adder to Compensate QFs for As-Yet-Unknown Environmental Upgrades Would Improperly Inflate Avoided Costs.**

45 The Commission should reject REC's arguments that costs associated with environmental upgrades be included in capacity payments for two main reasons: (1) in support of its arguments, REC appends to its declaration a piece of direct testimony that was filed in a different docket, with a different state commission, and by a person who is not a witness in the instant proceeding; and (2) REC's proposed adder to compensate QFs for as-yet-unknown environmental upgrades would improperly inflate avoided costs.

**a. Testimony Filed in a Different Proceeding, a Different State and by a Person Who Is Not a Witness in This Proceeding Must Be Given Very Little Weight**

46 Attached to Mr. Lowe's policy declaration is testimony of Mr. Kevin C. Higgins filed on behalf of REC, the Community Renewable Energy Association, OneEnergy, and Obsidian Renewables, LLC, in the Public Utility Commission of Oregon's Docket No. UM 1610. With no explanation or justification for this procedurally inappropriate appendix, Mr. Lowe simply submits Mr. Higgins' UM 1610 testimony in support of his argument that capacity payments should reflect costs associated with environmental upgrades required at thermal generating plants. Mr. Higgins is not a witness in this

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<sup>74</sup> *Id.*

docket, and his testimony is not part of the stipulated record in this proceeding. Rather, Mr. Higgins filed his testimony in response to related issues in an entirely separate proceeding before the Public Utility Commission of Oregon. This testimony is hearsay, and for that reason should be given very little weight in the instant proceeding.<sup>75</sup>

**b. Any Adder to Compensate QFs for As-Yet-Unknown Environmental Upgrades Would Improperly Inflate Avoided Costs**

47           Setting aside REC’s procedural sloppiness, REC’s substantive arguments are also fatally flawed for the following reasons:

- The referenced environmental upgrades include capital investment that cannot be avoided by the addition of a Washington QF, even one that is renewable or non-emitting.
- Several of the referenced environmental upgrades that were included in the IRP for planning are not currently required, and alternative compliance scenarios may eliminate the need for the investment irrespective of any new QF generation.
- There is no accounting for the benefits of the existing generation resources that will be lost if the environmental upgrades are eliminated.<sup>76</sup>

48           First, REC’s argument incorrectly implies the environmental upgrades at specific coal plants located in Utah, Wyoming, Colorado, Montana, and Arizona can be avoided by renewable and non-emitting QFs in Washington. This is incorrect. In reality, all of the upgrades listed by Mr. Lowe are for compliance with the Environmental Protection Agency’s (EPA) Regional Haze Rule, which is intended to improve the air quality and visibility in national parks and wilderness areas in the proximity of the emitting resource.<sup>77</sup> PacifiCorp cannot avoid these compliance costs by simply adding a 2 MW Washington QF. Furthermore, construction of several of the projects referenced is

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<sup>75</sup> See, e.g., Wash. R. Evid. 804(b)(1)(prior testimony of a witness is hearsay unless the proponent demonstrates that the witness is unavailable in the instant proceeding).

<sup>76</sup> Dickman Rebuttal Dec. at ¶ 24.

<sup>77</sup> *Id.* at ¶ 25.

already underway, underscoring the fact that costs cannot be avoided and should not be included in the determination of avoided costs.<sup>78</sup> REC's proposal must fail for this reason alone.

49           Second, REC's proposal is flawed because the list of capital projects it relies on includes selective catalytic reduction (SCR) projects for which there is no such requirement yet in place.<sup>79</sup> Under PURPA, utilities are not required to pay more than their avoided costs for QF purchases.<sup>80</sup> FERC has interpreted this cap on avoided cost to prohibit payment for environmental costs unless they are "real costs that would be incurred by utilities;" that is, costs that will *actually* be avoided.<sup>81</sup> A number of the upgrade costs listed in PacifiCorp's IRP, however, may turn out to be unnecessary as environmental requirements are finalized.<sup>82</sup> These upgrades do not qualify as the type of costs appropriate for inclusion in avoided cost under PURPA and FERC precedent.

50           Third, REC's proposal is also inappropriate because it fails to account for the benefits lost to the Company if the environmental upgrades are, in fact, eliminated. Elimination of the identified environmental upgrades would significantly affect the Company's generation portfolio. Coal plants provide low-cost base load generation, as well as operating reserves and load following capability.<sup>83</sup> The Company's IRP takes these benefits and other trade-offs into account when evaluating whether investments in environmental upgrades are appropriate. If the Company does not invest in an environmental upgrade that is required to comply with the Regional Haze Rule, the

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<sup>78</sup> *Id.* at ¶ 26.

<sup>79</sup> *Id.* at ¶ 27.

<sup>80</sup> *See, e.g.*, 16 U.S.C. § 824a-3(b) ("No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."); 18 C.F.R. § 292.304(a)(2).

<sup>81</sup> *So. Cal. Edison*, 71 FERC ¶ 61,269 at 62,080.

<sup>82</sup> As Mr. Dickman notes, alternatives to SCR installation (*e.g.*, retiring the unit altogether or converting it to be fueled by natural gas) may also be considered as requirements are finalized. Indeed, the timing of such compliance alternatives is often different than the SCR installation and also eliminates the cost of SCR installation. Once decisions on Regional Haze Rule-related investments are ripe, they will be included in an IRP for Commission review and acknowledgement. Dickman Rebuttal Dec. at ¶ 27.

<sup>83</sup> Dickman Rebuttal Dec. at ¶ 28.

Company will no longer be able to operate the plant as a coal-fired generator. Given the operational characteristics of a coal-fired plant and those of renewable QFs, it is impractical to replace an entire existing coal plant with many individual QFs.<sup>84</sup> Consequently, the proposal is simply inappropriate.

51 Finally, the fact that there is uncertainty about the final Section 111(d) rules does not lend credence to REC's arguments. On the contrary, the uncertain nature of the draft Section 111(d) rules and the impact on PacifiCorp's long-term resource plan is one more reason to *reject* REC's proposal to artificially inflate avoided costs. The Company will continue to plan future resource acquisitions to minimize costs and risk to customers.<sup>85</sup> The preferred portfolio in the Company's 2015 IRP minimizes cost and risk in complying with draft Section 111(d) rules. Imputing additional costs into the avoided cost formula on the premise of unknown and uncertain future changes to the proposed regulations, and based on unrelated compliance investments, will only overstate avoided costs and violate the ratepayer indifference standard embodied in PURPA.

### III. CONCLUSION AND REQUEST FOR RELIEF

52 To meet the objective of ratepayer indifference, deferred capacity costs must be included in avoided costs in a manner consistent with the Company's resource procurement plans identified in its IRP. The Company's filing is based on its 2013 IRP Update, which indicates that the next avoidable thermal resource will not be procured until 2027 and that the Company will rely on short-term wholesale market transactions to balance its capacity needs before that time. Artificially increasing avoided cost prices by including fixed costs of new generators that will not be acquired until at least 2027 or the cost of environmental upgrades at existing facilities that cannot be avoided by the

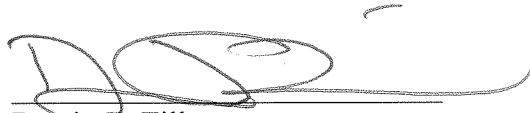
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<sup>84</sup> As Mr. Dickman points out, using the 36.7 percent capacity contribution for a single axis tracking solar project (the highest of the wind and solar capacity contributions) listed in the 2015 IRP, replacing a 350 MW share of the capacity lost by eliminating Jim Bridger Unit 3 would require over 950 MW of new solar capacity from QFs. This unrealistic result does not account for the lost dispatchability and lost energy from a base load generator. Dickman Rebuttal Dec. at ¶ 28.

<sup>85</sup> *Id.* at ¶ 29.

addition of Washington QFs overstates the costs that the Company will avoid and ultimately results in higher costs passed on to the Company's Washington retail customers. PacifiCorp respectfully asks the Commission to approve its proposed Schedule 37 tariff.<sup>86</sup>

Respectfully submitted this 11<sup>th</sup> day of September, 2015.

A handwritten signature in black ink, appearing to read "Dustin T. Till", written over a horizontal line.

Dustin T. Till  
Attorney for PacifiCorp

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<sup>86</sup> As noted, PacifiCorp has agreed to withdraw the proposed variable generation integration charges from its Schedule 37 in this docket, and will revise its Schedule 37 tariff sheets to reflect this withdrawal upon final resolution of this docket or at such time as the Commission orders.