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June 17, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: UM 1610 – Investigation into Qualifying Facility Contracting and Pricing
PacifiCorp's Post-Hearing Brief

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) encloses for filing in the above-referenced docket PacifiCorp's Post-Hearing Brief.

Please contact Joelle Steward, Director of Pricing, Cost of Service and Regulatory Operations, at (503) 813-5542 for questions on this matter.

Sincerely,

William R Griffith AS

William R. Griffith
Vice President, Regulation

Enclosure

Cc: Service List – UM 1610

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Post-hearing Brief on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 17th day of June 2013.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610
Phase I

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation Into Qualifying Facility Contracting and Pricing	PACIFICORP'S POST-HEARING BRIEF

I. INTRODUCTION

The Public Utility Commission of Oregon (Commission) opened this docket to investigate issues related to electric utilities' purchases from Qualifying Facilities (QFs) under the Public Utility Regulatory Policies Act (PURPA), following a series of recent issues related to the ongoing implementation of PURPA.[1] Following a number of workshops, the parties agreed to an issues list and to address the issues in two phases. This post-hearing brief sets forth PacifiCorp d/b/a Pacific Power's legal position on each applicable issue addressed in Phase I and a summary of the factual support for each position.

II. SCOPE OF THIS INVESTIGATION

This docket was opened to address generic legal and policy issues related to PURPA implementation and QF contracting.[2] The order issued by the Commission in this docket is likely to be an important one that will be referenced in the future by parties seeking guidance on generic Commission policy. Consequently, the ALJ has held that matters related to specific, ongoing factual disputes between parties will not be addressed in this docket.[3]

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[1] *In re Idaho Power Co.'s Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices,* and *In re Request to Revise Standard Contract Avoided Cost Prices Paid to Qualifying Facilities Under Schedule 85,* Dockets UM 1590 and UM 1593, Order No. 12-146 (April 25, 2012).
[2] *See Administrative Law Judges Ruling* at 2 (Apr. 30, 2013).
[3] *See* April 30, 2013 ALJ Ruling at 2 (so holding).

PacifiCorp and Threemile Canyon Wind I, LLC (Threemile Canyon) have an ongoing dispute, currently pending in docket UM 1546. One key issue in Threemile Canyon's complaint is the issue of third-party transmission costs. The Commission held in docket UM 1546 that the issue of third-party transmission costs affects utilities and QFs broadly, so it is appropriate to stay the proceedings in docket UM 1546 pending the resolution of the issue in this generic investigation. Docket UM 1546 currently remains stayed.[4] In deciding to stay the proceedings, the Commission noted that PacifiCorp had extended its short-term power purchase agreement (PPA) with Threemile Canyon to maintain the status quo during the stay, and thus Threemile Canyon had not shown that it was unduly harmed by the delay.[5] The status quo is therefore protected pending the outcome of this investigation, and pending the outcome of Threemile Canyon's complaint.

PacifiCorp raises these issues for two reasons. First, Threemile Canyon raises a number of factual issues in its testimony and pleadings in this docket related to specific factual and legal disputes between the parties.[6] The ALJs have held, both in rulings and during the hearing, that the order in this docket will *not* resolve specific, ongoing factual disputes, but will only address legal and policy issues in a generic fashion.[7] Based on these rulings, PacifiCorp will not offer a factual response to Threemile Canyon's gratuitous inclusion of disputed facts that pertain to the issues pending in docket UM 1546. Second, Threemile Canyon asks the Commission to determine in this docket whether the policy decisions made here will be prospective or retroactive in their application, and presumably to Threemile Canyon's pending dispute.[8] This

[4] *Threemile Canyon Wind I, LLC vs. PacifiCorp, dba Pacific Power*, Docket UM 1546, ALJ Ruling (Oct. 22, 2012) (holding that docket, initially stayed pending the outcome of docket UE 235, would continue to be stayed pending the outcome of docket UM 1610); *see also* Order No. 12-475 (Dec. 10, 2012) (Commission order affirming ALJ ruling).
[5] Order No. 12-475 at 3.
[6] Threemile Canyon's prehearing brief, for example, argues about PacifiCorp's state of mind during contract negotiations, an issue outside the scope of a generic proceeding. *See* Threemile Canyon's Prehearing Memorandum at 3-4(May 20, 2013).
[7] *See, e.g.,* April 30, 2013 Ruling at 2; Hearing Transcript at 101 (May 23, 2013) (ALJ Pines agreeing with PacifiCorp's objection that to the extent "the testimony or that cross-examination [offered by Threemile Canyon] is attempting to establish whether or not PacifiCorp and Threemile Canyon can have had [sic] a legally enforceable obligation," it is "outside the scope" of the docket, which is limited to "generic policy issues").
[8] Threemile Canyon's Prehearing Memorandum at 4-7 (May 20, 2013).

issue, like the specific factual issues, is outside the scope of a generic docket and may be unnecessary, depending on the outcome of the issues before the Commission in docket UM 1546.[9] PacifiCorp recommends the Commission make straightforward generic policy and legal decisions in this docket. Once it has done so, the complaint docket will resume and the effect of the generic decision can be assessed in docket UM 1546.[10]

III. DISCUSSION

The Commission's goal in implementing PURPA is to encourage the economically efficient development of QFs, while protecting utility customers by ensuring that utilities incur costs no greater than they would have incurred in lieu of purchasing QF power.[11] As the Commission has held, it is appropriate to encourage the development of QFs only to the extent that "ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs."[12] This investigation gives the Commission the opportunity to refine the balance between prices paid to QFs and costs incurred by retail customers. This balance is a one-for-one tradeoff, as every additional dollar paid to QF developers is ultimately borne by retail customers. A number of parties to this docket propose adjustments to QF prices, in particular adjustments to standard QF prices.[13] However, as they apply to standard QF prices, these adjustments are largely contrary to the Commission's stated policies on PURPA implementation.

The aim of calculating avoided costs is to "accurately estimate the costs a utility would incur to obtain an amount of power that it purchases from a QF, either by the utility's self-

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[9] During the hearing, Threemile Canyon attempted to cross-examine Adam Bless on this very issue. Hearing Transcript at 12-13 (May 23, 2013). PacifiCorp objected that "[t]he question of the applicability to future facilities versus existing is not an issue currently in front of the Commission." *Id.* Commission staff joined PacifiCorp's objection. *Id.* Threemile Canyon then withdrew its question. *Id.* Furthermore, Threemile Canyon appears to be the only party concerned about this issue.

[10] *See* Order No. 12-475 at 3 (upholding stay in docket UM 1546 and discussing effect of Commission's decision in this docket on complaint).

[11] *In re Staff's Investigation Relating to Elec. Util. Purchases from Qualifying Facilities,* Docket UM 1129, Order No. 07-360 at 1 (Aug. 20, 2007); *see also In re Staff's Investigation Relating to Elec. Util. Purchases from Qualifying Facilities* , Docket UM 1129, Order No. 05-584 at 11 (May 13, 2005); *see also* 16 U.S.C. § 824a-3(b), (d); *American Paper Inst., Inc.* v. *American Elec. Power Serv. Corp.,* 461 U.S. 402, 413 (1983); *see also Conn. Light & Power,* 70 F.E.R.C. ¶ 61,012 at p. 61,029 (1995).

[12] Order No. 05-584 at 11.

[13] *See* PAC/300, Dickman/2.

generation or by purchase from a third-party."[14] In addition, standard rates should be simple, transparent, and easy to administer. A lack of precision in standard rates is a deliberate balancing act, but the use of standard rates is a reasonable approach if eligibility for standard rates is kept within limits that minimize the impact of imprecise prices on utility customers. PacifiCorp's proposals to limit the standard rate eligibility cap to 3 megawatts (MW) or less, and use a model-based method for larger QFs, and allow more frequent updates to pricing inputs, including the demarcation point between sufficiency and deficiency periods, help to accurately reflect the realities of costs PacifiCorp faces to procure energy and capacity from QFs greater than 3 MW while maintaining transparency and simplicity for QFs up to 3 MW.

Issue 1: Avoided Cost Price Calculation

1A. What is the most appropriate methodology for calculating avoided cost prices?

PacifiCorp proposes using two distinct methodologies for calculating avoided costs: a standard method based on a proxy resource to calculate prices for QFs up to 3 MW (Proxy Method), and a model-based approach referred to as the partial displacement differential revenue requirement method (PDDRR Method) for QFs larger than 3 MW that captures resource-specific characteristics and impacts on the utility system to calculate a negotiated avoided cost price.[15]

A. The Commission Should Continue Use of the Proxy Method for Standard Avoided Costs (PacifiCorp's Schedule 37)

PacifiCorp supports the continued use of the Proxy Method for standard avoided costs. The Proxy Method reasonably balances the Commission's goals of encouraging QF development while maintaining utility customer indifference to QF power.[16]

Under the Proxy Method, standard rates during the deficiency period are based on a proxy plant that is fully dispatchable by PacifiCorp and is located at an optimum location relative to load.[17] To the extent that a QF, unlike the proxy plant, is not in an optimum location, is not

[14] Order No. 05-584 at 20.
[15] *See* PAC/100, Dickman/4-8.
[16] *See* Order No. 05-584 at 11.
[17] PAC/100, Dickman/5.

dispatchable, is not reliable, does not provide reserves, produces intermittent power, or does not allow PacifiCorp to schedule maintenance, prices paid to a QF under the standard contract are higher than they might otherwise be.[18] Nonetheless, for projects under 3 MW—which will not substantially impact a utility's load and resource plan—the Proxy Method strikes a reasonable balance between accuracy and transparency, and serves to minimize transaction costs for smaller and less sophisticated project developers.[19]

(1) For Ease of Administration, the Standard Avoided Cost Calculation Should Use Market Prices from the Mid-Columbia Hub, Rather than Blended Market Prices

PacifiCorp proposes one change to the standard avoided cost calculation during the sufficiency period— use of market prices from a single market hub, the Mid-Columbia hub, rather than blended market prices. Most parties appear to be supportive of this proposal.[20] In the past, PacifiCorp has been required to use multiple markets across its system and to apply weightings to the markets based on an analysis performed in its GRID production cost model.[21] PacifiCorp proposes to eliminate market blending because it adds unnecessary complexities and administrative burdens into PacifiCorp's standard avoided cost calculation without having a material impact on prices.[22] The Mid-Columbia market is an active market in PacifiCorp's western balancing authority area, and fairly represents the short-term energy value of small QF resources in Oregon. Using market prices from the Mid-Columbia hub would simplify the process without materially affecting prices.[23]

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[18] PAC/100, Dickman/5.
[19] *Id.* at 5-6.
[20] OneEnergy stated that it might support the change to a single market hub if PacifiCorp were to prepare a table comparing the annual avoided costs rates based on the (1) Mid-Columbia index and (2) the current blended index. *See* OneEnergy/100, Eddie/16-17. PacifiCorp provided this information in its most recent Schedule 37 filing, and in Exhibit PAC/301. Exhibit PAC/301 illustrates that the difference between the two price streams is approximately $0.20/MWh.
[21] *See* PAC/100, Dickman/6 (citing Order No. 05-584).
[22] *Id.* at 6-7.
[23] *See* Exhibit PAC/301. PacifiCorp disagrees with ODOE's assertion that the choice of a single market hub should depend on the location of the QF. ODOE's Prehearing Memorandum at 3. Exhibit PAC/301 demonstrates that using prices from the Mid-Columbia hub is both simple and appropriate.

(2) QF-Specific or Resource-Specific Adjustments to Standard Avoided Costs, Which Undermine the Purposes and Advantages of Standard Rates, Should Generally Be Avoided

Consistent with the Commission's findings in docket UM 1129, QF-specific or resource-specific adjustments to standard avoided costs, which undermine the purposes and advantages of standard rates, should generally be avoided.[24] The Commission should therefore reject proposals to adjust standard avoided costs to account for resource capacity contribution,[25] transmission and system upgrades,[26] and natural gas pipeline capacity or storage capacity.[27] If such adjustments are warranted, they should only be applied to non-standard avoided costs.[28]

Community Renewable Energy Association (CREA) argues that the proxy resource should reflect the cost to transmit power, including any necessary transmission upgrades.[29] This argument should be rejected because there is no support for the conclusion that the addition of QF resources requires fewer transmission upgrades or less transmission service than the addition of utility resources.[30] Under OAR 860-082-0035(4), QFs are responsible for the reasonable costs of system upgrades, which are defined as upgrades to the utility's transmission or distribution system *necessitated by the interconnection of a small generator facility.*[31] Accordingly, system upgrades that are not necessitated by the interconnection of the QF's facility are not the responsibility of the QF. Transmission infrastructure upgrades are needed to move resources to load regardless of what type of resource is added to the resource portfolio.[32] Transmission infrastructure costs that provide benefits to the system for both utility and QF resources should not be incorporated into standard avoided cost calculation. A similar rationale may be applied to address transmission service costs. Incremental transmission service costs directly attributable to

[24] Order No. 05-584 at 16 ("With standard contracts, project characteristics that cause the utility's cost savings to differ from its actual avoided costs are ignored."); *see also* PAC/300, Dickman/7-8.
[25] PAC/300, Dickman/13-14.
[26] *Id.* at 15-16.
[27] *Id.* at 17.
[28] *Id.* at 14.
[29] CREA's Pre-hearing Legal Brief at 10-11.
[30] PAC/300, Dickman/16.
[31] OAR 860-082-0035(4) (emphasis added).
[32] *Id.*

a QF (such as certain third-party transmission costs, discussed in more detail below) are appropriately borne by QFs while transmission service costs that are attributable to PacifiCorp's system resources (both utility and QF resources) should not be incorporated into the calculation of standard avoided cost.

B. The Commission Should Adopt the PDDRR Method for Calculating Non-Standard Avoided Costs (PacifiCorp's Schedule 38)

For both renewable and non-renewable negotiated non-standard avoided cost prices, PacifiCorp strongly urges the Commission to adopt the PDDRR Method, a differential revenue requirement approach that relies on information from PacifiCorp's integrated resource plan (IRP) and measures the impact a QF has on PacifiCorp's revenue requirement.[33] Independently calculating the avoided cost of large QFs using the PDDRR Method is a more accurate approach for determining the value of the energy and capacity on PacifiCorp's system than the current method of making individual adjustments to the Proxy Method because it directly measures the impact each QF has on PacifiCorp's net power costs.[34] PacifiCorp currently uses the PDDRR Method in Utah and Wyoming to calculate non-standard avoided cost prices.[35]

Currently, non-standard avoided costs are determined using the same Proxy Method used to set standard avoided cost prices, modified by a limited set of discrete adjustments meant to recognize some resource-specific characteristics.[36] The allowable set of adjustments was derived from the seven factors outlined in 18 C.F.R. § 292.304(e)(2).[37] Under federal law, these factors

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[33] PAC/100, Dickman/7-8.
[34] *Id.* at 8.
[35] *Id.*
[36] This method was adopted in Order No. 07-360.
[37] 18 CFR § 292.304(e)(2) states that the following factors shall, to the extent practicable, be taken into account:

> i) The ability of the utility to dispatch the qualifying facility;
> ii) The expected or demonstrated reliability of the qualifying facility;
> iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirements, and sanctions for non-compliance;
> iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
> v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

are to be taken into account where practicable in setting avoided costs.[38] But the Commission's current method takes into account only a subset of these factors, including dispatchability and reliability. Others are addressed as separate contract issues, and still others are not addressed by the Commission's current methodology at all.[39] PacifiCorp's experience in other jurisdictions is that a differential revenue requirement approach like the PDDRR Method successfully accounts for all seven of the factors in 18 C.F.R. § 292.304(e)(2).

(1) <u>The PDDRR Method Represents an Improvement over the Existing Proxy Method</u>

The PDDRR Method uses PacifiCorp's production cost model, GRID, to calculate the value of energy and capacity from a given QF based on the unique characteristics of the QF and PacifiCorp's system.[40] The method uses two GRID runs—one with a specific QF and one without—to account for additional energy and capacity provided by the QF and to allow for a dynamic re-dispatch of PacifiCorp's system.[41] The model takes into account the QF's specific operating characteristics and point of delivery on PacifiCorp's system using the best information available to PacifiCorp at the time the QF pricing is prepared. This ensures that the PDDRR Method provides accurate avoided cost prices and maintains retail customer indifference.[42] Using the PDDRR Method, QF avoided costs consist of three main components: avoided capacity costs, avoided energy costs, and integration costs (where appropriate).[43] The PDDRR Method also provides a capacity payment based on the cost of the "next deferrable resource" in PacifiCorp's preferred portfolio.[44] In applying the capacity payment, the method accounts for

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vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

[38] *See* PAC/100, Dickman/9-10.

[39] *Id.*

[40] *Id.* at 9.

[41] *Id.* at 11; PAC/300, Dickman/9.

[42] PAC/100, Dickman/15-16.

[43] The methodology for calculating each of these key components is detailed at PAC/100, Dickman/12-14.

[44] PAC/100, Dickman/11.

the difference between the capacity value provided by QF resources and the next deferrable resource, including the capacity contribution of the QF resource.[45]

The PDDRR Method represents an improvement over the Proxy Method for several reasons. First, unlike the existing method, the PDDRR Method takes into account the Commission's currently authorized adjustment factors, additional statutory factors under 18 C.F.R. § 282.304(e)(2), other relevant resource-specific factors (for example, location and generation profile), and accurately accounts for the avoided capacity costs, avoided energy costs, and, where appropriate, variable energy integration costs.[46]

The Proxy Method fails to account for a number of these critical factors and also makes inaccurate assumptions about costs being incurred. For example, the Proxy Method assumes that PacifiCorp can always use the output of a given QF to make additional wholesale sales, or avoid making wholesale purchases, during the resource sufficiency period; it also assumes that PacifiCorp can always save the variable cost of the IRP proxy resource during the resource deficiency period. As PacifiCorp explained in testimony, these assumptions are not accurate in every circumstance.[47] These assumptions in the Proxy Method can cause the prices derived from the Proxy Method to be higher than actual avoided costs. The PDDRR Method remedies these problems by directly measuring the impact each QF facility has on PacifiCorp's net power costs. Staff and the Renewable Energy Coalition (REC) concede that a differential model-based method like GRID more accurately measures avoided costs.[48]

Second, the PDDRR Method allows for updating the modeling inputs as often as practical to ensure that avoided costs are based on the best information available.[49]

Third, use of the PDDRR Method is consistent with prior Commission decisions rejecting a proxy approach in favor of using differential GRID runs.[50] The Commission has recognized in

[45] *Id.*
[46] PAC/100, Dickman/10-15.
[47] *See Id.* at 8-9.
[48] *See, e.g.,* Staff/100, Bless/8; Coalition/200, Schoenbeck/9.
[49] *See* discussion of Issue 3, Schedule for Avoided Cost Price Updates, *infra.*
[50] PAC/300, Dickman/11 (citing *In re Investigation into Direct Access Issues for Indus. and Commercial Customers Under SB 1149*, Docket UM 1081, Order No. 04-516 at 10-11 (Sept. 14, 2004)).

other contexts, such as PacifiCorp's annual transition adjustment mechanism (TAM) filing, that PacifiCorp's differential GRID runs are superior to a proxy method because they better capture the actual costs that are appropriate for customers and the utility to bear. PacifiCorp creates multiple GRID modeling runs annually in connection with PacifiCorp's TAM filing, and they form the basis for PacifiCorp's Commission-approved annual transition adjustment for direct access customers. PacifiCorp asks the Commission to reach the same conclusion regarding the calculation of avoided costs: that a differential modeling approach will best account for actual, appropriate operational responses, yield a more accurate calculation of non-standard avoided costs, and therefore best determine the costs that ratepayers should pay large QFs under PURPA.[51]

(2) Objections to the PDDRR Method Are Misplaced

A number of parties have argued that the PDDRR Method lacks transparency. PacifiCorp believes these concerns are misplaced, particularly when weighed against the benefits of the model's accuracy. Balance between transparency and accuracy is an important consideration in avoided cost pricing. With respect to transparency, however, the GRID model is neither new nor novel. PacifiCorp has used the GRID model to calculate net power costs across its service territory since 2002, subjecting the model to over a decade of rigorous scrutiny by regulators and intervenors.[52] It is used to calculate net power costs in PacifiCorp's annual Oregon TAM filings and it is used to produce avoided cost prices for QF projects in Utah, Idaho, and Wyoming.[53] PacifiCorp has made the model available at no cost to developers and intervenors. In short, the model has been widely available and has a proven track record for multiple uses across multiple jurisdictions. While using a production cost model may be more

[51] PacifiCorp disagrees with REC's assertion that the impact of calculating non-standard avoided costs under the current method compared to the PDDRR method is negligible. *See* Coalition/200, Schoenbeck/10. While the PDDRR method and the existing Proxy Method can produce similar results, they can also be very different depending on the circumstances. *See* PAC/300, Dickman/13.
[52] PAC/300, Dickman/10.
[53] *Id.* PacifiCorp prepared over 40 PDDRR pricing studies last year alone.

complex than the current Proxy Method, the GRID model has a long track record of use and availability.

As QF projects increase in size and relative impact, it is important that avoided cost prices be as accurate as possible. As PacifiCorp noted, the potential impact of an 80 MW wind farm QF on PacifiCorp's system is significant. At current prices, total payments to the wind QF over 20 years would exceed $200 million.[54] Given the widespread use and availability of the GRID model, the balance between transparency and accuracy weighs in favor of utilizing the PDDRR Method. While any model is only as good as its inputs, the GRID model reflects the unique characteristics of PacifiCorp's system and the actual costs that are avoided with each unique QF, and thus is a far more accurate method.[55]

While a number of parties state they would prefer to retain the Proxy Method because of its relative transparency, it is not clear that retaining the Proxy Method would yield a methodology that is simple or transparent. Significant debate exists, just in this docket, over whether the Commission should allow a number of additional adjustments to be made to the Proxy Method to ensure the Proxy Method is a reasonably accurate representation of avoided costs.[56] In PacifiCorp's view, adopting the PDDRR Method, in conjunction with lowering the eligibility cap for standard prices, is a more accurate and streamlined way to *improve* avoided cost calculations than layering additional adjustments on top of the existing Proxy Method.

1B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

The Commission declined to adopt any option for levelization in docket UM 1129.[57] PacifiCorp agrees with Staff that no party has given the Commission a reason to revisit this issue or to reverse its prior decision. Levelization in avoided cost pricing introduces additional

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[54] PAC/100, Dickman/10.
[55] PAC/300, Dickman/6.
[56] *See, e.g.,* OneEnergy's Prehearing Issues Brief at 3-4 (May 20, 2103) (requesting that if the Commission modifies the existing methodology by adopting certain utilities' refinements to the methodology, it should simultaneously implement the refinements raised by QFs).
[57] *See* Order No. 05-584 at 28, fn 46.

customer risk in the early years of a QF PPA, when payments are higher than they would be under non-levelized pricing. Levelization also undermines one of the Commission's primary goals when addressing PURPA issues–ensuring that avoided costs are calculated accurately[58]–because levelization causes avoided costs payments to diverge from a utility's avoided cost price stream for that year.[59] Levelization would also add an additional layer of unnecessary administrative complexity to the billing and security provisions of a PPA.

1C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different from the market price?

PacifiCorp agrees with Staff that the Commission should not adopt preferential pricing options for current QFs seeking a contract renewal.[60] A number of parties argue that existing projects should be treated differently than new QFs because they have been included as part of a utility resource portfolio, but this argument is based on a false assumption about the relationship between a utility and a QF.[61] The relationship between a QF and the utility is a contractual arrangement that begins and ends with the dates set forth in the PPA. PacifiCorp has no ability to force a QF to continue operation beyond the contract term. Consequently, from a retail customer perspective, there is no difference between a QF seeking contract renewal and a new QF.[62] In docket UM 1129, the Commission set the QF contract length at a 20-year term.[63] Extending sufficiency period pricing for contract renewal effectively extends the maximum contract length, is an inappropriate policy result, and cannot be counted on by the utility in any event.[64]

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[58] Order No. 05-584 at 26.
[59] PAC/200, Griswold/5.
[60] *See* Staff/100, Bless/13-14.
[61] *See, e.g.,* Coalition/200, Schoenbeck/12-13.
[62] PAC/300, Dickman/18-19.
[63] Order No. 05-584 at 20.
[64] PAC/100, Dickman/16; *see also* PAC/300, Dickman/18.

1D. Should the Commission eliminate unused pricing options?

The Gas Market Indexed and Banded Gas Market Indexed avoided cost pricing options should be eliminated from PacifiCorp's standard avoided cost options.[65] These pricing options have been available for over seven years, but no QF under the standard avoided cost eligibility cap has ever entered into a contract using either option.[66] In the interest of simplifying the standard avoided cost price options and reducing transactional costs for QFs, PacifiCorp supports eliminating these options. While no party objects to PacifiCorp's proposal to remove these options from Schedule 37, CREA takes the position that utilities should be required to make these currently-unused price options available by request.[67] In PacifiCorp's view, requiring a utility to maintain pricing options that are available only "on request" undermines a key purpose of a utility tariff: to provide a publicly available document detailing the rates and terms for service as PacifiCorp's Schedule 37 provides for the standard QF.[68] Consistent with this purpose, the unused pricing options should simply be eliminated.

Issue 2: Renewable Avoided Cost Price Calculation

2A. Should there be different avoided cost prices for different renewable generation sources?

Consistent with the Commission's order in docket UM 1396, both standard and non-standard avoided cost prices should be differentiated for intermittent and non-intermittent renewable resources.[69] Accordingly, PacifiCorp proposes adjusting avoided costs prices for integration costs for QFs supplying intermittent generation. This issue will be discussed in greater detail in section 4A below.

Staff's proposal to gross up the capacity payments included in the renewable avoided costs for a QF's capacity contribution relative to the renewable proxy should not be adopted.

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[65] PAC/400, Griswold/6.
[66] PAC/200, Griswold/6.
[67] CREA/200, Reading/14; CREA's Prehearing Legal Brief at 5.
[68] PAC/400, Griswold/7.
[69] *See* PAC/100, Dickman/17-19; *see In re Investigation into Resource Sufficiency Pursuant to Order No. 06-538*, Docket UM 1396, Order No. 11-505 at 4-5 (Dec. 13, 2011). PacifiCorp proposes to use its calculated wind integration costs for both wind resources, and as a proxy for integrating solar resources. PAC/100, Dickman/19.

The next avoidable renewable resource in the Company's IRP is a utility scale wind facility, which on a capacity-adjusted basis is already more expensive than a base load CCCT. Combining the full fixed cost of a wind facility and the fixed costs of a CCCT overstates the cost of capacity on PacifiCorp's system.[70]

2B. How should environmental attributes be defined for purposes of PURPA transactions?

Environmental attributes should be defined as the environmental, social, and other positive, non-energy characteristics of electricity generation from a renewable resource, consistent with the Oregon Department of Energy's (ODOE) rule OAR 330-160-0015(3).[71]

2C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contracts?

If adequate language is incorporated into the standard contract to ensure that selecting the renewable avoided cost price requires the QF to transfer the non-energy attributes to the utility in periods of renewable resource deficiency, then it is not necessary to amend OAR 860-022-0075.[72]

Issue 3: Schedule for Avoided Cost Price Updates

3A. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgment?

To increase the accuracy of avoided cost prices, it is critical that inputs to the avoided cost calculation be updated as often as practical. Under PacifiCorp's recommendation, which would use different methodologies for calculating standard and non-standard avoided costs, the timing of updates would differ for standard and non-standard avoided cost prices.

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[70] PAC/300, Dickman/20-21.
[71] PAC/200, Griswold/7-9; *see also* PAC/400, Griswold/7-8. OAR 330-160-0015(3) defines a Renewable Energy Certification as "a unique representation of the environmental, economic, and social benefits associated with the generation of electricity from renewable energy sources that produce Qualifying Electricity. One Certificate is created in association with the generation of one MegaWatt-hour (MWh) of Qualifying Electricity. While a Certificate is always directly associated with the generation of one MWh of electricity, transactions for Certificates may be conducted independently of transactions for the associated electricity."
[72] PAC/400, Griswold/8-9.

A. Schedule for Updating Standard Avoided Cost Prices

For standard avoided costs prices, including renewable avoided cost prices, PacifiCorp recommends the Commission require an annual update, as well as an update within 30 days following Commission acknowledgment of an IRP.[73] PacifiCorp supports the adoption of a fixed filing date for an annual standard cost update, but asks the Commission to set a date in the fourth quarter for such updates to avoid conflicts with other annual filings.[74]

Some parties have proposed limitations to the inputs that may be included in annual updates, such as market prices of gas and electricity, execution of contracts, and changes in load forecasts.[75] While PacifiCorp supports limiting the inputs that are updated annually, it is critical that the Commission allow a utility to update the timing of the resource sufficiency period in any annual update. If a utility cannot update the timing of the resource sufficiency period in an annual update, the ability to update for changes in load and contracts is simply not meaningful.[76] As the Commission noted in Order No. 05-584, one of the Commission's primary goals is to "ensure that avoided costs are calculated accurately," and the accurate calculation of avoided costs "requires differentiation when a utility is in a resource sufficient position versus a resource deficient position."[77] A utility's ability to update the timing of its resource deficiency period in an annual update based on known changes to a utility's preferred portfolio is critical to ensure that an annual update improves the accuracy of avoided cost prices.

REC's argument that annual updates should be deferred when they are scheduled to occur within 90 days of acknowledgement of an IRP is unworkable. A utility cannot predict the Commission's acknowledgement of an IRP. REC's suggestion would simply result in confusion and uncertainty for both utilities and QFs.[78]

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[73] *See* PAC/300, Dickman/22.

[74] *Id.* Staff suggests that annual updates be made on March 1 of each year, but this is the date PacifiCorp makes its annual TAM filings, as well as its general rate filings in years in which it files an Oregon general rate case. PacifiCorp believes that REC's proposal that utilities make annual updates one year from the effective date of then-current prices is unnecessarily complex compared to a fixed calendar date for annual updates.

[75] *See, e.g.,* Coalition/200, Schoenbeck/17-18.

[76] PAC/300, Dickman/23.

[77] Order No. 05-584 at 26.

[78] PAC/300, Dickman/24-25.

B. Schedule for Updating Non-Standard Avoided Cost Prices

For non-standard avoided cost prices, PacifiCorp recommends that inputs to the PDDRR Method be updated using the best information available at the time the QF requests prices. Ensuring that underlying assumptions and modeling inputs are as accurate as possible—including forward market prices of electricity and natural gas, purchase and sale contracts for energy and capacity, and contracts for wheeling, transportation of natural gas and coal—will help ensure that retail customers are indifferent to the calculated avoided cost price.[79] PacifiCorp recommends that at the time a QF requests prices, forward market prices for electricity and natural gas be based on PacifiCorp's most recent official forward price curve, and purchase and sale contracts for energy and capacity—as well as contracts for wheeling, transportation of natural gas, and coal—be updated to include all executed transactions.[80]

3B. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?

3C. Should the Commission specify what factors can be updated in mid-cycle?

In docket UM 1129, the Commission acknowledged that mid-cycle avoided cost filings may be appropriate[81] but did not specify criteria to justify mid-cycle updates. PacifiCorp urges the Commission to allow mid-cycle updates when there are known changes in a utility's preferred resource portfolio.[82] Using stale information from the last acknowledged IRP could result in the utility acquiring QF resources at prices that do not reflect the utility's known changes in resource needs.[83] IRP forecast and cost assumptions are used to develop a forward-looking portfolio to serve anticipated customer demand while minimizing cost and risk. But IRP forecasts are not necessarily used to make resource acquisitions; when PacifiCorp is considering whether to make new acquisitions, it uses the most recent information available.[84]

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[79] PAC/100, Dickman/22.
[80] *Id.*
[81] Order No. 05-584 at 29.
[82] *See* PAC/100, Dickman/20; PAC/300, Dickman/26-28.
[83] PAC/300, Dickman/27.
[84] *Id.* at 26.

A recent request for proposals (RFP) demonstrates this: during PacifiCorp's 2011 RFP, PacifiCorp updated its load forecast and used it to update its resource needs assessment. The updated resource needs assessment demonstrated that the resource sought in the 2011 RFP was no longer needed, and the RFP was discontinued.[85] This ongoing and continuous evaluation of resource needs was supported by both Staff and the Commission.[86] Had PacifiCorp continued to rely on out-of-date information from its 2011 IRP in making its decisions about resource acquisition, it would have acquired a resource that it no longer needed. The Commission should not require PacifiCorp to acquire QF resources on a different basis than PacifiCorp acquires its own resources. Allowing mid-cycle updates when there are known changes in a utility's preferred resource portfolio will help ensure that avoided costs are appropriate.

For non-standard prices, PacifiCorp believes it is critical that all model inputs reflect the best information available at the time the request is made.[87]

3E. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

The RPS Implementation Plan should <u>not</u> be used in lieu of the acknowledged IRP to determine renewable resource sufficiency for purposes of setting an avoided cost rate.[88] The calculation of standard avoided costs for a renewable resource should be consistent with the calculation for a non-renewable resource, with the key difference being the relevant proxy resource. The RPS Implementation Plan is too limited to serve this purpose for renewable resource sufficiency. It is used to calculate the cost limitation of complying with the RPS and covers only a five-year period. By contrast, the IRP evaluates RPS compliance obligations over a longer time horizon, identifies the timing of PacifiCorp's next deferrable resource, evaluates renewable resource needs across PacifiCorp's six-state service territory, and provides the basis

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[85] *Id. See In re PacifiCorp Request for Approval of Final Draft 2011 All Source Request for Proposals,* Docket UM 1540, Administrative Law Judge Ruling (Oct. 3, 2012).
[86] PAC/300, Dickman/26-27.
[87] *See* PAC/100, Dickman/22.
[88] *Id.* at 19. The RPS Implementation Plan is filed under ORS 469A.075 and OAR 860-083-0400.

for various assumptions in the RPS Implementation Plan.[89] In short, the IRP is the appropriate tool for determining renewable resource sufficiency.

Issue 4: Price Adjustments for Specific QF Characteristics

4A. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?

The costs associated with integration of intermittent resources should be included in the calculation of standard and non-standard avoided cost prices. Although PacifiCorp is generally opposed to distinguishing standard avoided cost rates based on resource-specific characteristics, PacifiCorp supports the Commission's conclusion that the distinction between intermittent and non-intermittent resources is a useful one.[90] Integration costs will not be included in the standard renewable avoided cost pricing option during the deficiency period, because during deficiency periods the proxy wind resource will also incur wind integration costs.[91]

PacifiCorp proposes to calculate the cost of integrating intermittent resources on its system by relying on its wind integration analyses, most recently its 2012 Wind Integration Study. These studies are based on company operational data and are used in the IRP and to set rates in general rate cases and should form the basis for the integration costs used in the calculation of renewable avoided costs.[92]

PacifiCorp proposes that integration costs be incorporated into avoided costs for all types of intermittent resources.[93] For standard avoided costs, PacifiCorp proposes specifying in Schedule 37 that the price offered to intermittent QFs during the renewable resource sufficiency

[89] PAC/100, Dickman/19.
[90] Order No. 11-505 at 5.
[91] PAC/100, Dickman/17.
[92] *See* PAC/100, Dickman/18. For solar resources, PacifiCorp's wind integration study is the closest estimate of the costs to integrate intermittent resources on PacifiCorp's system, and thus PacifiCorp proposes using the results of its wind integration study for both wind and solar resources. *See id.* at 19; PAC/300, Dickman/32-34.
[93] PAC/300, Dickman/32.

period will be reduced for the cost of integration.[94] Standard avoided cost prices for intermittent renewable resources would be adjusted by the cost of integration identified in PacifiCorp's IRP.

CREA proposes that small QFs (under 10 MW) should not be required to pay integration costs.[95] In support of this, CREA cites to the unspecified benefits of small projects that it argues balance out the cost of wind integration.[96] CREA's argument is flawed in that it fails to balance the benefits of small projects with the disadvantages of QF resources relative to the proxy resource.[97] More fundamentally, CREA's argument fails because the Commission only recently decided this issue in docket UM 1396, where the Commission affirmed that the difference between intermittent and base load QFs is a distinction that should be recognized in standard avoided cost prices.[98]

A number of parties also argue that integration costs should be modified based on the location of the QF or to account for the benefits of geographic diversity (in terms of lower integration costs) attributable to QFs.[99] As noted above, PacifiCorp's wind integration costs are based on its most recent wind integration study. This study utilizes actual operational data from PacifiCorp's fleet of generating resources and includes wind projects located across its expansive six-state system.[100] As a result, geographic diversity is already built in to the integration cost and no further adjustments are warranted. Furthermore, it is unclear how the benefits of geographic diversity could be quantified.[101] In addition, the proposal to modify the integration cost based on geographic location is unworkable because it would be difficult, and likely contentious, to identify specific boundaries for location-based integration costs.[102] As such, not only is this

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[94] PAC/100, Dickman/17. Because the proxy wind resource used to calculate avoided costs during the *deficiency* period would also incur wind integration costs, PacifiCorp would not include an adjustment for integration costs to renewable avoided cost pricing during the deficiency period.
[95] CREA Pre-hearing Legal Brief at 8.
[96] CREA/200, Reading/16.
[97] PAC/300, Dickman/30.
[98] Order No. 11-505 at 5, 9.
[99] *See e.g.*, ODOE/100, Carver/9-10.
[100] PAC/300, Dickman/31.
[101] *Id.*
[102] *Id.*

complication not warranted, it is likely to increase confusion and disputes. The Commission should therefore reject these proposals.

Some parties also appear to argue that base load renewable resources should receive an adjustment for avoided integration costs during the deficiency period.[103] However, the Commission addressed this issue in Order No. 11-505, which granted renewable resource QFs the option to choose between the renewable resource avoided cost and the standard avoided cost.[104] This decision was made to allow the renewable QF to choose the standard avoided cost rate to better reflect the value of the base load renewable resource.[105] Therefore, under this logic, so long as renewable QFs have the option to select the standard non-renewable avoided cost stream it is unnecessary for the renewable avoided cost to be adjusted for base load renewable resources during the deficiency period.

For non-standard contracts, PacifiCorp proposes to adjust avoided cost prices to reflect integration costs calculated for each year based on differential GRID model runs. These model runs would use the wind integration study results to calculate the cost of incremental reserves needed to integrate intermitted generation over the term of the QF contract using updated modeling inputs (such as forward market prices) in GRID.[106]

4B. Should the costs or benefits associated with third-party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

Payments to QFs under PURPA must be just and reasonable, non-discriminatory, and not in excess of a utility's avoided cost.[107] This principle is violated if PacifiCorp is required to pay third-party transmission costs that are directly attributable to a QF and in excess of costs

[103] CREA/300, Svendsen/3-7.
[104] Order No. 11-505 at 5.
[105] *Id.* at 9.
[106] PAC/100, Dickman/18.
[107] 16 U.S.C. § 824a-3(b); *Am. Paper Inst,. Inc,.* 461 U.S. 402 at 413 (PURPA "sets full avoided cost as the maximum rate that the Commission may prescribe"); *Indep. Energy Producers Ass'n v. Pub. Util. Comm'n of Cal.,* 36 F.3d. 848, 850 (9th Cir. 1994) (PURPA sets full avoided cost as the maximum rate that the Commission may prescribe); *see also Conn. Light & Power Co.,* 70 FERC ¶ 61,012 at p. 61,029 (1995) (state-imposed rates for purchase of QF output which exceed the purchasing utility's avoided cost violate PURPA and FERC regulations).

PacifiCorp would incur to purchase power from non-QF facilities. PacifiCorp therefore proposes that the costs or benefits of third-party transmission that are attributable to an individual QF be reflected in an addendum to the relevant QF contract.[108] Under PURPA, this is required when: 1) third-party transmission costs are in excess of costs PacifiCorp would normally incur; and 2) third-party transmission costs would not be incurred but for the existence of the QF resource. PacifiCorp proposes that the costs or benefits of third-party transmission caused by a specific QF be calculated outside the avoided cost rate, and treated in a similar manner as generator interconnection costs.[109]

PacifiCorp's system is not continuous; rather, it is made up of a series of what PacifiCorp refers to as "load pockets."[110] Load pockets vary significantly in size,[111] and are connected, in most cases, through transmission owned by a third-party such as the Bonneville Power Administration. PacifiCorp purchases third-party transmission in order to move energy between load pockets.[112] Because load pockets are of different sizes, some load pockets are more or less able to absorb additional generation inside the load pocket. If the generation in a load pocket exceeds the amount of load, generation inside the load pocket must be backed down, or the excess generation must be moved (via third-party transmission) to a load pocket with sufficient load to absorb the excess generation.[113] These periods, which typically occur during an off-peak period or during seasonal periods when loads are low, are referred to as Excess Generation Events.

The current method for calculating the standard avoided cost—the Proxy Method—represents the Commission's determination of full avoided cost. As noted earlier, the proxy resource is assumed to be optimally located relative to load[114] and is considered an on-system

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[108] *See* PAC/400, Griswold/12.
[109] *See* PAC/200, Griswold/10.
[110] PAC/200, Griswold/10-11.
[111] *See* CREA/504.
[112] PAC/200, Griswold/11.
[113] *Id.*
[114] PAC/100, Dickman/5.

resource because it is assumed to be directly interconnected to PacifiCorp's system.[115] Transmission costs are therefore not included in the calculation of full avoided cost. This is appropriate because, in the aggregate, additional on-system QFs do not necessarily allow PacifiCorp to avoid transmission costs.[116]

In addition, the proxy resource does not include third-party transmission costs because, generally, PacifiCorp would not opt to locate a new on-system resource inside a load pocket where the resource would cause the generation in the load pocket to exceed load.[117] If PacifiCorp's proxy resource was an off-system resource, and third-party transmission was required to move the resource's generation to PacifiCorp's system, presumably the costs of third-party transmission would be included in the cost of the proxy resource. PacifiCorp understands that this approach is consistent with Portland General Electric Company's treatment of third-party transmission costs.[118] Similarly, under PURPA, an off-system QF choosing to sell to PacifiCorp would be required to purchase transmission to move its resource's output to PacifiCorp's system.[119]

Under PURPA and the Commission's rules implementing PURPA, customer indifference is ensured by relying on a "but-for" causation principle when determining the avoided cost rate and accompanying charges.[120] Under this evaluation, costs that would not otherwise be incurred *but for* the purchase of the QF's energy and capacity must be recovered from the QF. Requiring PacifiCorp to pay Schedule 37 rates (representing full avoided cost) plus an additional cost to obtain third-party transmission results in PacifiCorp paying more than full avoided costs. This violates Commission policy and federal law.

[115] Hearing Transcript at 107.
[116] *See infra,* at 6-7.
[117] PAC/400, Griswold/12.
[118] PGE/300, Macfarlane – Morton/17 ("We assumed that the avoided resource is out of system and include BPA wheeling in the avoided cost").
[119] *See* 18 CFR § 292.303(d).
[120] 16 U.S.C. § 824a-3(b), (d); OAR 860-029-0010(1); *see also In re Investigation into Avoided Cost Purchases from Qualifying Facilities—Schedule 37*, Docket No. UE 235, PacifiCorp Reply Brief at 6.

In docket AR 521, the Commission held that QFs under 10 MW should "pay for system upgrades that are 'necessitated by the interconnection of a small generator facility' and 'required to mitigate' any adverse system impacts 'caused' by the interconnection."[121] Third-party transmission costs are analogous to these interconnection costs, in the sense that PacifiCorp would not incur third-party transmission costs to move QF output out of load pockets during Excess Generation Events *but for* the purchase of the QF's energy and capacity.[122]

When a QF chooses to locate a resource inside a load pocket where the output of that resource will exceed the load in the load pocket, the third-party transmission costs incurred by PacifiCorp are directly attributable to the QF. PacifiCorp would not be required to incur these third-party transmission costs *but for* the QF.[123] Therefore, if PacifiCorp's customers are required to pay for these third-party transmission expenses to move the QF's output out of a load pocket, then customers are subsidizing the QF. This violates PURPA.[124]

The arguments from other parties fundamentally misunderstand PacifiCorp's proposal, are therefore misplaced, and fail to adequately address the violation of the indifference standard that would be caused by requiring a utility to pay for the third-party transmission costs directly caused by a QF.

Threemile Canyon argues, among other things, that PURPA contains no avoided-cost exception for "load pockets."[125] This misstates PacifiCorp's position. PacifiCorp uses the term "load pockets" to describe the geography and circumstances under which PacifiCorp may incur additional costs, above and beyond its avoided costs, in order to purchase QF power. PacifiCorp

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[121] *In re Rulemaking to Adopt Rules Related to Small Generator Interconnection*, Docket AR 521, Order No. 09-196 at 5 (June 8, 2009). The Commission made similar findings with respect to large QF generators in docket UM 1401. *See In re Investigation into Interconnection of PURPA Qualifying Facilities with Nameplate Capacity Larger than 20 Megawatts to a Pub. Util.'s Transmission or Distribution System*, Docket UM 1401, Order No. 10-132 at 3 (Apr. 7, 2010).
[122] PAC/400, Griswold/11-12.
[123] *Id.* at 12. PacifiCorp faces the same issue with non-QF resources, but addresses the additional costs or excess generation problem through contract price adjustment or curtailment of the resource. PAC/200, Griswold/15.
[124] *See, e.g., Am. Paper Inst. Inc,* 461 U.S. at 413; *Indep. Energy Producers Ass'n,* 36 F.3d. at 850; *see also Conn. Light & Power Co.,* 70 FERC ¶ 61,012 at p. 61,029 (state-imposed rates for purchase of QF output which exceed the purchasing utility's avoided cost violate PURPA and FERC regulations); *S. Cal Edison Co. v. Pub. Util. Comm'n of Cal.*, 101 Cal. App. 4th 384, 398 (2002).
[125] Threemile Canyon's Prehearing Memorandum at 11.

is not arguing that PURPA directly addresses "load pockets"; PacifiCorp argues that PURPA addresses avoided costs. And under PURPA, PacifiCorp should not incur costs *above avoided costs* to purchase QF power.[126]

Threemile Canyon also argues that, under 18 C.F.R. §292.303(d), avoided costs may account for third-party transmission costs only when the QF is making indirect sales to a utility.[127] This application of the federal rule is misguided. The C.F.R. section cited by Threemile Canyon (Part 292, Section 303) is entitled "Electric utility obligations under this subpart." It focuses not on the avoided costs rates under PURPA, but on the more general issue of a utility's obligations under PURPA. One issue addressed in Section 303 is whether indirect QF sales—that is, sales from a QF to a utility that first require another utility to wheel the power across its transmission system—are appropriate under PURPA. Under certain conditions, the rule explains, a utility is required to purchase power wheeled across another utility's transmission lines and the rule describes the appropriate handling of such transactions.[128] But the propriety of indirect sales and the appropriate rates for indirect sales are not at issue here. PacifiCorp's recommendation regarding third-party transmission costs addresses the appropriate PURPA rates for *direct* sales. PURPA's rate setting rules are found not in Section 303, but in the subsequent section, Section 304, entitled "Rates for purchases." Section 304 specifically addresses the appropriate parameters for payments from utilities to QFs under PURPA (the issue here), and it states in relevant part as follows: "*Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases*."[129] PacifiCorp's proposal regarding QF third-party transmission costs ensures, consistent with federal rules, that a utility pays no more than avoided costs for QF purchases.[130]

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[126] 18 C.F.R.§ 202.304(a)(2).
[127] Threemile Canyon's Prehearing Memorandum at 10.
[128] *See* 18 C.F.R.§ 202.303(d).
[129] 18 C.F.R.§ 202.304(a)(2).
[130] Threemile Canyon also suggests that PacifiCorp's proposal discriminates against QFs. Threemile Canyon's Prehearing Memorandum at 12-13. While PacifiCorp does pay third-party transmission costs in certain situations, those situations do not invoke PURPA's prohibition against paying more than avoided costs for QF power. *See* PAC/400, Griswold/14. And as noted previously, PacifiCorp faces a similar transmission issue with non-QF resources, but addresses the additional costs or excess generation problem through contract price adjustment or

As an apparent attempt to undermine PacifiCorp's proposal, both CREA and Threemile Canyon go to great lengths to establish that PacifiCorp incurs third-party transmission costs for its own resources and that PacifiCorp pays third-party transmission costs for off-system resources.[131] These parties apparently argue that because PacifiCorp's own resources incur these costs, it is discriminatory to require QFs to bear these costs. However, what both CREA and Threemile Canyon fail to recognize or acknowledge is that, as already explained, PacifiCorp's proxy resource does not assume *any* transmission costs and that PacifiCorp does *not* incur third-party transmission costs associated with an on-system generation resource located in a load pocket where the generation in the load pocket exceeds the amount of load. Furthermore, the third-party transmission costs cited by Threemile Canyon and CREA are utilized to move PacifiCorp resources *and QF resources* between load pockets. PacifiCorp is not proposing to somehow allocate third-party transmission costs to QFs generally. Rather, it is proposing to allocate costs to a QF where those costs are directly attributable to that QF and would not have been incurred *but for* the QF resources.

CREA also argues that PacifiCorp's own resources may require transmission system costs in the form of system upgrades. PacifiCorp does not dispute that its own resources may require transmission system upgrades; however, the transmission infrastructure upgrades cited by CREA[132] are generally large-scale system upgrades that are not attributable to any specific resource, but rather benefit the system as a whole.[133] PacifiCorp is not proposing to assign these types of system upgrade costs to QFs. Accordingly, the costs should not be included in the calculation of PacifiCorp's standard avoided cost.

Some parties also argue that requiring an addendum to account for third-party transmission costs undermines the Commission's policy of minimizing transactional costs for

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curtailment of the resource. PAC/200, Griswold/15. But under the mandatory purchase obligations of PURPA, PacifiCorp must purchase QF output regardless of where it is located. PAC/400, Griswold/15.

[131] Threemile/200, Harvey/14-15; CREA/200, Reading/18-20.

[132] *See* CREA/503.

[133] *See* Hearing Transcript at 28-29.

small QFs.[134] As noted previously, the Commission has, indeed, stated that it will provide incentives for the development of QFs of all sizes, but in doing so, it has emphasized, it will ensure "that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs."[135] In other words, the Commission's incentives for small QFs are premised on the condition of customer indifference. Requiring PacifiCorp to pay third-party transmission costs on top of avoided costs undermines this indifference. Moreover, the Commission's current approach to small QFs currently contemplates some individual negotiation, as long as it is "specifically delineated and bounded."[136] PacifiCorp's proposal would be limited in nature: PacifiCorp is simply proposing an addendum for transmission usage based on publicly available contract rates that are both transparent and verifiable. It would not materially increase the transactional costs associated with the negotiation of a standard contract.

In short, PacifiCorp's proposal to assign the costs and benefits of third-party transmission to QFs is appropriate and should be adopted in this docket for a number of reasons. It (1) ensures compliance with PURPA; (2) retains the avoided cost methodology adopted in UM 1129 (and the methodology under consideration here); (3) is consistent with Commission policy, which already assigns certain costs, *e.g.,* interconnection costs, directly to QFs on a case-by-case basis; (4) proposes to pass on only verifiable and transparent third-party costs incurred pursuant to publicly available transmission tariffs or rate schedules; (5) is applicable only to that subset of Schedule 37 QFs in load-constrained areas requiring third-party transmission to serve load; and (6) treats third-party transmission costs and savings symmetrically.[137]

4C. How should the seven factors of 18 CFR 292.304(e)(2) be taken into account?

PacifiCorp proposes applying the PDDRR Method to determine non-standard avoided costs. This methodology accounts for the resource-specific characteristics identified by 18

[134] Order No. 05-584 at 16 (standard contracts "are intended to be used as a means to remove transaction costs associated with QF contract negotiations, when such costs act as a market barrier to QF development.")
[135] Order No. 05-584 at 11.
[136] *Id.* at 39.
[137] PAC/400, Griswold/13.

C.F.R. § 292.304(e)(2), as well as additional relevant, resource-specific factors, such as the QF's location, delivery pattern, and capacity contribution.[138] However, PacifiCorp proposes that, consistent with the Commission's rejection of adjustments to standard QF avoided costs in Order No. 05-584, the Commission should decline to adopt adjustments to standard avoided cost rates.[139]

Issue 5: Eligibility Issues

5A. Should the Commission change the 10 MW cap for the standard contract?

The current maximum nameplate capacity rating eligible for standard avoided costs is 10 MW. PacifiCorp proposes lowering this cap to 3 MW.[140] The purpose of offering a standard avoided cost contract is to remove market barriers for small QFs, including transactional costs associated with contract negotiations.[141] Yet, as the Commission has stated, the Commission must "balance our interest in reducing these market barriers with our goal of ensuring that a utility pays a QF no more than its avoided costs for the purchase of energy."[142] A 3 MW cap would ensure that transaction costs for small QFs are minimized, while at the same time improving the accuracy of avoided cost payments for the majority of QFs and mitigating a number of additional issues of concern.

As noted previously, standard avoided cost rates may reflect an inherent overpayment to QFs to the extent a QF is not fully dispatchable and located at an optimum location relative to load—that is, to the extent the QF's characteristics are not as optimized as the characteristics of the proxy plant on which standard avoided costs are based.[143] Few, if any of the QF resources eligible for standard avoided cost prices produce energy that provides equivalent value to the proxy resource energy.[144] For this reason, PacifiCorp's customers generally pay higher costs for

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[138] *See* PAC/100, Dickman/9-11.
[139] PAC/300, Dickman/35-40.
[140] *See* PAC/200, Griswold/20-21.
[141] Order No. 05-584 at 16.
[142] *Id.*
[143] PAC/100/Dickman/5.
[144] *Id.*

QF resources receiving standard avoided cost pricing than they would actually pay for the proxy resource. The Commission's interest in ensuring that a utility pays "no more than its avoided costs" for QF energy therefore supports lowering the eligibility cap.

On the other side of the scale is the Commission's interest in ensuring that market barriers do not render certain smaller QF projects uneconomic.[145] Since Order No. 05-584 was issued, PacifiCorp's experience has been that QFs over 3 MW generally have technical, business, and legal experts engaged in the analysis, development, and contracting phases of their project and are capable of negotiating non-standard contracts.[146] In fact, since the cap has been increased over time to 10MW, PacifiCorp now negotiates with well-funded, experienced developers who have developed many projects and hire some of the most skilled technical and legal firms in the country.[147] Indeed, the Commission's 10 MW cap is the highest in the six-state region served by PacifiCorp.[148] PacifiCorp's experience indicates that a 3 MW eligibility cap for standard contracts would continue to encourage the development of additional community-scale resources across all resource types and include under the cap projects that may otherwise be unable to afford the transaction costs of negotiating a non-standard rate.[149]

Not only would a 3 MW cap effectively balance the interests identified by the Commission, it would also mitigate other problems, such as the inappropriate disaggregation of large single projects into multiple projects (because it would be much more difficult for smaller projects to disaggregate) and the issue of third-party transmission costs.[150]

PacifiCorp disagrees with Staff's qualified recommendation that the Commission retain the 10 MW cap, a recommendation predicated on the Commission's adoption of Staff's proposed

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[145] *See* Order No. 05-584 at 16; *See also* Final Rule: Small Power Production and Cogeneration Facilities, F.E.R.C. Order No. 69, 45 Fed. Reg. 12,214, 12,223 (Fed. 25, 1980) (codified at 18 C.F.R. Part 292) (noting that transaction costs associated with negotiating individualized avoided cost rates would likely render the program uneconomic for QFs under 100kW).

[146] PAC/400, Griswold/17.

[147] PAC/200, Griswold/19.

[148] *See* Exhibit PAC/200. While some states do have eligibility caps greater than 3 MW, they also have lower eligibility caps for specific resource types such as wind or solar.

[149] PAC/200, Griswold/20.

[150] PAC/200, Griswold/15-16. A lower cap would reduce the potential for a QF's generation to exceed load in a load pocket, and therefore reduce third-party transmission costs related to the purchase of QF power.

modifications to the standard and renewable avoided cost calculation methodologies. As argued in Issue 1, above, PacifiCorp believes that Staff's proposed modifications to the standard avoided cost calculations will unnecessarily increase the administrative complexity of updating and validating standard avoided cost prices and should not be adopted.[151] PacifiCorp would note that Staff agrees with PacifiCorp's proposed 3 MW cap in the event Staff's proposed modifications to standard avoided cost calculations are rejected.[152]

5B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?

PacifiCorp proposes that the partial stipulation adopted in docket UM 1129 be modified to remove the passive investor exception.[153] The purpose and intent of the partial stipulation was to develop a mechanism that would give independent family or community-based QF projects an exemption from the single-site restriction so that these projects could share common infrastructure and have common passive investors without violating PURPA or state regulations.[154] In practice, however, the passive investor exception has allowed large projects to circumvent the intent of the partial stipulation and devise ownership structures that allow them to disaggregate and still technically meet the Commission's eligibility criteria.[155]

PacifiCorp therefore recommends the Commission eliminate the passive investor exception and allow an exemption *only* for independent family or community-based projects. This would prevent abuse of Commission policy through disaggregation. If the Commission decides to retain the passive investor exception, PacifiCorp requests that it consider ways to ensure that the intent of the exception—to allow independent family or community-based

[151] PAC/400, Griswold/16-17. Other parties make similar recommendations with respect to modifying the standard avoided cost calculation in various ways. PacifiCorp believes a 3 MW cap is the cleanest and most administratively efficient way to reconcile the Commission's competing objectives in establishing standard avoided-cost rates.
[152] Staff/100, Bless/37.
[153] *See* PAC/200, Griswold/25.
[154] *Id.* at 23.
[155] *Id.* at 23-24.

projects to share common infrastructure and have common passive investors—is appropriately effectuated.[156]

5C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF?"

Wind and photovoltaic solar resources are capable of disaggregating into multiple projects.[157] Lowering the standard avoided costs eligibility cap to 3 MW and removing the passive investor exception discussed under issue 5B would significantly mitigate the problem of disaggregation of large projects.

Issue 6: Contracting Issues

6B. When is there a legally enforceable obligation?

Under PURPA, a QF may sell to a utility either under a contract, or through a legally enforceable obligation (LEO).[158] A LEO may be established when a QF commits itself to sell to an electric utility.[159] Individual states determine when a LEO is incurred under state law.[160] The purpose of the LEO is to prevent the utility from avoiding purchasing from a QF by refusing to sign a power purchase agreement with the QF as well as to establish a threshold standard a QF must meet in order to qualify to sell to a utility.[161] In some instances, PacifiCorp has experienced QFs attempting to establish a LEO through various means, including simply downloading a form contract, signing it, and sending it to PacifiCorp.[162] Therefore, criteria for establishing a LEO should be clear, provide certainty for both the utility and the QF, and to the extent possible, prevent both the utility and the QF from attempting to frustrate or manipulate the establishment of a LEO.

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[156] *Id.* at 25-26.
[157] *Id.* at 26.
[158] *Cedar Creek Wind, LLC,* 137 F.E.R.C. ¶ 61,006 at P 32 (2011). Under FERC regulations, a QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA. *Id.*
[159] *Murphy Flat Power, LLC,* 141 F.E.R.C. ¶ 61,145 at P 24 (2012).
[160] *West Penn Power Co.*, 71 F.E.R.C. ¶ 61,153 at P 13 (1995).
[161] PAC/200, Griswold/28; *See* F.E.R.C. Order No. 69.
[162] PAC/200, Griswold/28.

PacifiCorp contends that it is reasonable to establish that a LEO has arisen when the QF approves the final draft contract as contemplated in section B(5) on page 10 of Schedule 37.[163] This ensures that a LEO is established only after the QF and utility have engaged in contract negotiations (for non-standard contracts) and exchanged critically important commercial, safety, and resource planning information.[164] Establishing the LEO when the QF approves the final draft contract is also reasonable in the context of specific requirements and timelines contained in Schedule 37, which restrict PacifiCorp's ability to frustrate the establishment of a LEO through extended negotiations.[165]

This is not, as some parties suggest, a point at which PacifiCorp has complete control of the process. Under the procedures outlined in Schedule 37, the applicable steps are as follows: (1) the QF obtains the standard form PPA from PacifiCorp's website; (2) the QF provides project information to PacifiCorp in writing sufficient to obtain a project-specific PPA; (3) upon receipt of the required information, PacifiCorp provides a draft PPA to the QF within 15 business days; (4) if the QF desires to proceed, it requests a final draft PPA in writing, along with any additional or clarified project information PacifiCorp reasonably deems necessary, at which point PacifiCorp must deliver the final draft PPA within 15 business days of receiving the requested information; (5) the QF may then review the agreement and either approve it or prepare written comments and proposals; if it provides comments, PacifiCorp must respond within 15 days; and (6) when both parties are in full agreement, PacifiCorp will prepare and send the QF a final executable PPA within 15 business days.[166] At step 5, the QF may still have lingering disputes with PacifiCorp, yet under PacifiCorp's proposal, a "legally enforceable obligation" would still have arisen.

If the parties reach step 5 and come to an impasse, a QF would have the ability to seek relief at the Commission for any disputes involving the terms of a long-term PPA; that is, any

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[163] *Id.* at 27-31.
[164] *Id.* at 31.
[165] *Id.* at 28.
[166] PacifiCorp's Oregon Schedule 37 at 9-10.

disputes that would prevent the parties from reaching step 6. A review of the procedures detailed in Schedule 37 makes it difficult to see how PacifiCorp's proposal puts the utility entirely in control of the process. To the contrary, it simply ensures that a LEO is established only after the QF and utility have engaged in contract negotiations (for non-standard contracts) and exchanged critically important commercial, safety, and resource planning information. These negotiations between the parties ensure that the QF is, in fact, committing itself to sell electricity as required by PURPA.[167]

6E. How should contracts address mechanical availability?

PacifiCorp currently uses an output guarantee, rather than a mechanical availability guarantee (MAG) for all QF resources except wind QFs and QFs delivering power on a non-firm basis.[168] There is currently no industry standard MAG for wind projects, although it is widely believed that the North American Electric Reliability Corporation will require owners of wind project to report outage data in the future.[169] PacifiCorp recommends increasing the MAG in its standard QF contracts. Specifically, for new wind QF contracts, the Guaranteed Availability should be increased from 0.875 to 0.90 for contract year three and all remaining contract years for the term of the contract. For existing QF projects that are renewing a contract or have previously had a contract with another utility, the Guaranteed Availability should be set at 0.90 starting in contract year one. In PacifiCorp's experience, wind QFs have consistently demonstrated an ability to meet these levels of Guaranteed Availability after excluding hours lost to force majeure and scheduled maintenance.[170]

In addition, PacifiCorp's current definition for availability in its standard QF contract allows 240 hours per year per wind turbine for scheduled wind turbine maintenance. PacifiCorp

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[167] *See, e.g., Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 at P 39.
[168] PAC/203.Griswold/2-3. PacifiCorp would prefer an output guarantee over a MAG even for wind QFs, but PacifiCorp has found that wind QFs are unwilling or unable to provide an output guarantee and will only provide a MAG. *Id.* at 3.
[169] *Id.* at 3-4.
[170] *Id.* at 4.

proposes reducing this to 60 hours per wind turbine. PacifiCorp's recent experience demonstrates that this change is reasonable.[171]

6I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

The Commission should continue the current 20-year maximum contract length, but reduce the fixed-price portion of the contract from 15 years to 10 years. The fundamental objective of the Commission-mandated contract terms is to "establish a maximum standard contract term that enables eligible QFs to obtain adequate financing, but limits the possible divergence of standard contract rates from actual avoided costs."[172] In terms of balancing interests, it is important that the Commission adopt a fixed-price term that is no longer than necessary to allow a QF to obtain financing. A longer term fixed-pricing term represents a downside for utilities and their customers. The longer the fixed-price component of the contract term, the greater the risk to utilities and their customers of incurring an uneconomic PPA.[173]

PacifiCorp believes that the existing 15-year *fixed price* portion of the allowed contract term tips the balance too far to one side of the scale, and proposes that the initial fixed-price portion of the contract term be reduced to 10 years.[174] This would provide a QF with certainty in the early years, while aligning contract prices in future years with prices closer to actual avoided costs. PacifiCorp's experience shows that adopting a shorter term for the fixed-price portion of the contract would not adversely affect a QF's ability to secure financing.[175] Since Order No. 05-584 was issued in 2005, PacifiCorp has executed standard PPA with 38 new construction QF projects totaling 195.5 MW of varying resource types.[176] All are commercially operating or under construction except one, which was terminated for default unrelated to financing. Forty-three percent of these new construction QF projects elected contract terms of 15 years or less,

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171 *Id.* at 5.
172 Order No. 05-584 at 19.
173 PAC/200, Griswold/33.
174 *Id.* at 32.
175 *Id.* at 32-33 (detailing PacifiCorp's experience with a wide variety of new QF projects, most of which elected for shorter-term contracts).
176 PAC/200, Griswold/32.

and half chose terms of 10 years or less.[177] In other words, even with the option of longer contract terms, QFs have elected contract terms shorter than the Commission's existing maximum-length contract and successfully obtaining financing while doing so.

In light of its contracting experience, PacifiCorp questions the assertions of a number of parties, including REC, OneEnergy, and CREA that contracts with fixed-price terms of longer than ten years are a necessary predicate to QF financing.[178] PacifiCorp has seen that a 20-year contract term with a 10-year fixed-price term is sufficient to allow a QF to obtain financing, complete construction, and begin commercial operation. In light of this experience, PacifiCorp questions the policy benefit of adopting a fixed-price term of longer than ten years, when a longer fixed-price term simply shifts more price risk to retail customers.[179]

PacifiCorp would also note that a QF's ability to recover its investment does not end when the initial contract expires. Assuming the plant is still operational, a QF may still make sales to the utility (if the PURPA purchase obligation is still in place) or it may sell its output to third parties. The Commission-established contract term simply limits the time period for which fixed pricing is based on an initial projection of avoided costs; it does not limit the time period over which a QF may recover its investment.[180]

Staff takes a somewhat flexible position on the issue of the appropriate length for the fixed term potion of the contract, suggesting that the Commission adopt a maximum contract term of 20 years with a fixed price term of at most 15 years.[181] In the end, Staff recommends the Commission retain its current policy because, Staff testifies, the issues are the same now as they were when the Commission issued Order No. 05-584. PacifiCorp would simply point out that PacifiCorp's experience since the issuance of Order No. 05-584 is detailed in its testimony. This

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[177] *Id.* at 33.
[178] *See, e.g.,* Coalition/100, Lowe/20 (arguing that the current contract length is needed to meet QF financing and long-term planning needs); OneEnergy/100, Eddie/38 (arguing that distributed generation QFs require fixed-price contracts of up to 25 year in length to obtain financing); CREA/200, Reading/35 (arguing that a 15-year fixed rate term is the minimum for QF financing and that a 20-year fixed-price term would be reasonable).
[179] PAC/400, Griswold/28.
[180] PAC/200, Griswold/33.
[181] Staff/100, Bless/40.

experience, which was unavailable when Order No. 05-584 was issued, demonstrates that a 10-year fixed-price term appears to allow QFs to obtain financing. Consequently, PacifiCorp would respectfully disagree with Staff's assertion that the Commission should retain the status quo from 2005, since additional experience and information is now available to the Commission.

III. CONCLUSION

PacifiCorp respectfully requests that the Commission adopt the proposals contained herein.

Respectfully submitted this 17th day of June, 2013.

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