PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

January 5, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

RE: UM 1734 —PacifiCorp's Prehearing Brief

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket its Prehearing Brief.

If you have questions about this filing, please contact Erin Apperson, Manager of Regulatory Affairs, at (503) 813-6642.

Sincerely,

R Bryce Dalley

R. Bryce Dalley
Vice President, Regulation

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1734

In the Matter of PACIFICORP d/b/a PACIFIC POWER Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap.	**PACIFICORP'S PREHEARING BRIEF**

I. INTRODUCTION

In its May 21, 2015, Application, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) asked the Public Utility Commission of Oregon (the Commission) to resolve two straight-forward issues regarding the terms of PacifiCorp's contracts with qualifying facilities (QFs) under the Public Utilities Regulatory Policy Act (PURPA). First, PacifiCorp asked the Commission to reduce the 15-year fixed price term for standard QF power purchase agreements (PPAs) to three years. Second, PacifiCorp ask the Commission to reduce the eligibility threshold for standard PPAs and pricing from 10 MW to 100 kW for solar and wind QFs. Record evidence demonstrates that PacifiCorp is experiencing an historic onslaught of new QF PPA requests. If the Commission's current policies remain unchanged, QF developers will continue to hoist capacity, regardless of need, on PacifiCorp's customers via long-term contracts that pose significant financial risk.

The Commission's mandate under PURPA is to promote (but not guarantee) renewable energy while ensuring customer indifference to QF purchases. The current contracting framework is unbalanced and has tipped the scales in favor of QF development at customers' expense. Because PURPA imposes a mandatory must-purchase obligation on utilities, they have no ability to object to QF purchases—even when such purchases are not the least-cost, least-risk option. PacifiCorp currently is facing a must-purchase obligation from thousands of MWs of new QF projects requesting long-term PPAs across its six-state system. Oregon law, however, authorizes the Commission to rebalance the terms of PacifiCorp's QF purchases to ensure that customers are not exposed to risky long-term contracts for capacity in isolation of basic resource planning principles and without a robust competitive procurement process at prices that exceed actual avoided costs.

By seeking to correctly resize the eligibility threshold and reset the fixed-price term, PacifiCorp is not seeking to end its must-purchase obligations under PURPA. PacifiCorp will remain obligated to purchase the output from eligible generating facilities at the appropriate avoided cost price. QFs with capacity exceeding a lowered eligibility cap will still be able to sell their output to PacifiCorp. But rather than qualifying for generic standard Schedule 37 prices, QFs exceeding the new threshold will receive more accurate avoided cost prices and PPA terms that are tailored to individual facilities under Schedule 38. Furthermore, the QFs fear of a lowered fixed-price term is equally unfounded. PacifiCorp will remain obligated to purchase eligible QF output for a three year fixed-price term, and eligible QFs will be able to renew their contracts for a new fixed-price term upon the expiration of the initial term.

II. LEGISLATIVE AND REGULATORY BACKGROUND

Congress enacted PURPA in response to the nationwide energy crisis of the 1970s. Its goal was to reduce the country's dependence on imported fuels by encouraging the addition of cogeneration and small power production facilities to the nation's electrical generating system.[1] PURPA requires electric utilities to purchase all electric energy made available by QFs at rates that (1) are just and reasonable to electric consumers, (2) do not discriminate

[1] See, e.g., 16 U.S.C. § 260 1 (Findings).

against QFs, and (3) do not exceed "the incremental cost to the electric utility of alternative electric energy."[2] The incremental cost to the utility means the amount it would cost the utility to generate or purchase the electric energy but for the purchase from the QF.[3] The incremental cost standard is intended to leave customers economically indifferent to the source of a utility's energy by ensuring that the cost to the utility of purchasing power from a QF does not exceed the cost the utility would incur without the QF purchase.[4]

In 1980, FERC issued rules implementing PURPA that included a utility's "avoided costs" as the standard for implementing the incremental cost requirement.[5] While the applicable statutes and rules are matters of federal law, PURPA delegates to state regulatory authorities the responsibility of determining a utility's avoided costs, as well as terms and conditions of PURPA contracts.[6]

As this Commission and state regulators across the country have stated time and time again, under PURPA's original intent, retail customers should be indifferent to the purchase of QF power. As early as 1981, the Commission has explained that the primary goal of its PURPA policies was:

---

[2] 16 U.S.C. § 824a-3; ORS 758.515(2)(b) ("It is the goal of Oregon to ... [insure] that rates for purchases by an electric utility from [a QF] shall be ... just and reasonable to the electric consumers of the electric utility ....")
[3] The provisions of 16 U.S.C. § 824a-3(d) provide the following definition of "incremental cost of alternative electric energy": For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.
[4] Indep. Energy Producers Ass 'n, Inc. v. California Pub. Utilities Comm'n, 36 F.3d 848, 858 (9th Cir. 1994) ("If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize QFs because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere.").
[5] See American Paper Inst. v. American Elec. Power Serv., 46 1 U.S. 402, 406 (1 982) (stating that "the term full 'avoided costs' used in the regulations is the equivalent of the term 'incremental cost of alternative electric energy' used in § 2 1 0(d) of PURPA"). FERC's regulations define the term "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." 18 C.F .R. § 292.101 (b)(6).
[6] *Idaho Power Co. v. Idaho Pub. Util. Comm'n.*, 155 Idaho 780, 782 (201 3) ("*Idaho Power Co.*")(citing *FERC v. Mississippi*, 456 U.S. 742, 75 1 (1982)).

> [T]o provide maximum economic incentives for development of qualifying facilities while insuring that the costs of such development do not adversely impact utility ratepayers who ultimately pay these costs.[7]

The Commission has repeatedly acknowledged the importance of ratepayer indifference when setting PURPA policies.[8] Indeed, the Commission has identified ratepayer indifference as its "primary aim."[9]

FERC has likewise affirmed the need to ensure ratepayer indifference to utility purchases of QF power, noting that, 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."[10] As PURPA's legislative history makes clear, PURPA was intended to encourage cogeneration and small power production, but it was not intended to provide subsidies to QFs.[11] The modifications requested by the Company in this docket are necessary to ensure that the Company's customers pay no more than avoided costs and remain indifferent to the Company's mandatory QF purchase obligations.

Although PURPA's federal mandate requires utilities to purchase QF power, its scheme of cooperative federalism gives state regulatory agencies the authority to protect

---

[7] Docket No. R-58, Order No. 81-319 at 3 (May 6, 1981).

[8] *See, e.g.*, Docket No. UM 1129, Order No. 05-584 at 11 (May 13, 2005) ("We seek to provide maximum incentives for the development of QFs of all sizes, while ensuring that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs."); Docket UM 1129, Order No. 06-538 at 37 ("[O]ur overriding goals in this docket are to encourage QF development, while ensuring that ratepayers are indifferent to QF power."); Docket No. UM 1129, Order No. 07-360 at 1 (Aug. 20, 2007) ("This Commission's goal is to encourage the economically efficient development of QFs, while protecting ratepayers by ensuring that utilities incur costs no greater than they would have incurred in lieu of purchasing QF power (avoided costs)"); Docket No. UM 1610, Order No. 14-058 at 12 (Feb. 24, 2014) ("We first return to the goal of this docket: to ensure that our PURPA policies continue to promote QF development while ensuring that utilities pay no more than avoided costs.").

[9] Order No. 05-584 at 45 ("In balancing the goals of facilitating QF contracts while sufficiently protecting ratepayers, we recognize that the primary aim is to ensure that ratepayers remain indifferent to the source of power that serves them.").

[10] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269, 62,080 (1995) overruled on other grounds, *Cal Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010).

[11] 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 co generators or small power producers.").

retail customers from any unintended negative consequences of these mandatory purchases by delegating to state authorities the freedom to establish the key terms and conditions of PURPA contracts.[12]

Under FERC's PURPA regulations, each QF has the option to provide energy or capacity to an electric utility pursuant to "a legally enforceable obligation for the delivery of energy or capacity over a specified term based on either the utility's avoided costs calculated at the time of delivery, or calculated at the time the obligation is incurred."[13] While FERC has created the abstract framework for the application of PURPA through its regulations, the states have been delegated authority to determine the specific details of how such contracts will be executed.[14] In crafting their methodologies for the details of PURPA contracts, FERC has explained its view that "states are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with [FERC's] regulations."[15]

The contract term is a critical element that has been left for state utility commissions to determine. The importance of establishing an appropriate fixed-price term cannot be underestimated because FERC generally requires utilities to lock in forecasted avoided cost prices for the entire contract term. It is true that underestimations of avoided costs may be

---

[12] Order No. 14-058 at 3; *Exelon Wind I, LLC*, 766 F.3d 380, 394-95 (5th Cir. 2014).
[13] 18 C.F.R. § 292.304(d)(2).
[14] *See, e.g., Cuero Hydroelectric, Inc. v. The City of Cuero, Tex.*, 85 FERC ¶ 61,124, 61,467 (1998) ("The Commission's established policy is to leave to state regulatory authorities or nonregulated electric utilities and to appropriate judicial fora, issues relating to the specific application of PURPA requirements to the circumstances of individual QFs."); *Metropolitan Edison Co.*, 72 FERC ¶ 61,015, 61,050 (1995) ("It is up to the States, not this Commission, to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law. Similarly, whether the particular facts applicable to an individual QF necessitate modifications of other terms and conditions of the QF's contract with the purchasing utility is a matter for the States to determine. This Commission does not intend to adjudicate the specific provisions of individual QF contracts."); *Indep. Energy Producers Ass'n*, 36 F.3d at 856 ("[T]he states play the primary role in calculating avoided costs and in overseeing the contractual relationship between QFs and utilities operating under the regulations promulgated by the Commission.").
[15] *Cal. Pub. Util. Comm'n*, 1 33 FERC ¶ 61,059 at P 24 (2010).

balanced out by overestimations during the term of a contract; however, the longer the fixed-price term, the longer customers (and QFs) are exposed to contract prices that deviate from actual avoided cost prices (whether due to imperfections in long-term forecast methodologies or unforeseeable market conditions). FERC has not spoken directly to the appropriate fixed-price term for PPAs, but the bedrock customer indifferent standard supports reasonably-short fixed-price terms that allow avoided cost prices to reset.

Under PURPA, states are tasked with assessing the needs of the state, the idiosyncrasies of the local utility systems, and the reliability and quality of potential power sources.[16] And it is the states that are implementing standards within FERC's PURPA framework in a manner consistent with the public interest. As the Fifth Circuit recently held in *Exelon Wind*, a case overruling FERC and upholding a state decision on a PURPA issue delegated to the states, "state regulatory agencies-rather than FERC-were empowered to define the parameters of the circumstances in which Qualified Facilities could form [legally enforceable obligations] … It is this essential holding which binds us here: under the cooperative federalism scheme created by PURPA, it is the [state] PUC, rather than FERC, that defines the parameters for when a Qualified Facility may form a [legally enforceable obligation]."[17] The length of a PURPA contract, like the creation of a legally enforceable obligation, is an issue delegated to the states under PURPA.

The contract term for PURPA contracts set by this Commission has never been static—it has varied since PURPA's inception. In 1996, as competitive markets began to emerge, the Commission limited QF contract terms to five years. On October 30, 1996, PGE

[16] *See FERC v. Mississippi*, 456 U.S. 742, 767 (1982) (explaining that PURPA "establishes a program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs.").
[17] *Exelon Wind I, LLC*, 766 F.3d at 396.

filed Advice No. 96-21, which proposed five-year term limits on QF contracts. In support of the term limit, PGE represented that a QF contract longer than five years posed significant risk to PGE and its ratepayers because the majority of long term power purchase contracts being negotiated in the energy market at the time were for periods of three to five years.

In its memo to the Commission, Staff stated: "[g]iven the continued movement toward a competitive marketplace for electricity and the prevalence of wholesale transactions for terms of five years or less," it is difficult to justify long-term QF contracts. [18] The Commission adopted PGE's filing at its December 1996 public meeting, thereby establishing a five-year contract length standard beginning in 1997.

In 2005, in Docket UM 1129, the Commission revisited the term issue with an objective to establish a maximum standard contract term that allowed financing but limited the possible divergence of standard contract rates from actual avoided costs. In Order No. 05-584 the Commission increased the fixed price contract term to 15-years, stating: "[w]e conclude that the contract term length minimally necessary to ensure that most QF projects can be financed should be the maximum term for standard contracts."[19] We are now faced with the same concerns as in 1996 when the position taken by Staff and the Commission is consistent with the same request the Company is now making: in today's energy markets, long-term QF power purchase agreements pose significant price risk and harm to the Company's customers because these QF contracts are longer than the typical contracting and hedging horizons for energy contracts in the utility industry today.

[18] Staff Report for December 17, 1996 Public Meeting, at 4.
[19] Order No. 05-584 at 19.

III. ARGUMENT

A. Modifying the Eligibility Threshold and Fixed-Price Term is Necessary to Protect Customers

Record evidence demonstrates that PacifiCorp is being flooded with requests for new QF PPAs.[20] If unabated, the pace of QF development (both in Oregon and across PacifiCorp's six-state system) under current contracting conditions exposes PacifiCorp's customers to significant harm. Between February 24, 2014 (when the Commission issued Order No. 14-058), and May 21, 2015 (when PacifiCorp filed its Application), PacifiCorp experienced a striking increase in requests for new long-term QF PPAs. During that time, the Company executed 104 MW of new Oregon QF PPAs.[21] At the time of filing, the Company had 338 MW of executed QF PPAs in Oregon, and another 587 MW in active requests for Oregon QF PPAs.[22] Those 925 MW of existing and proposed PURPA contracts in Oregon at their nameplate capacity would supply 56 percent of the Company's average Oregon retail load and 90 percent of the Company's minimum Oregon retail load.[23]

When PacifiCorp's six-state system is taken into consideration, the increase in QF PPA requests is more dramatic. As of May 24, 2015, PacifiCorp had requests for 4,017 MW of new PURPA contracts system-wide.[24] That amount is in addition to the 1,991 MW of QF contracts that were executed and operating or under construction.[25] The 6,008 MW of executed and proposed PURPA contracts at their nameplate capacity would supply

[20] *See, e.g.*, PAC/100, Griswold/3.
[21] PAC/100, Griswold/2-3.
[22] PAC/100, Griswold/3.
[23] PAC/100, Griswold/3.
[24] PAC/100, Griswold/3-4.
[25] PAC/100, Griswold/4.

88 percent of PacifiCorp's average retail load and 121 percent of PacifiCorp's minimum retail load.[26]

The dramatic increase in executed and proposed QF PPAs, combined with 15-year fixed price terms, exposes PacifiCorp's customers to significant price risk. Over the next decade, PacifiCorp's expected system-wide payments to QFs with executed PPAs is $2.9 billion.[27] In 2015 alone, PacifiCorp is projected to pay $170.5 million to QFs on a total-company basis, with Oregon's allocated share at $42.6 million.[28] If the avoided costs paid under these PPAs are priced higher than market alternatives by just 10 percent, it would create a $4.3 million impact in 2015 for PacifiCorp's Oregon customers.[29] The pricing risk faced by customers will only amplify as the 4,017 MW of QF capacity currently in the PPA queue come online with long-term, fixed-price contracts.

QF developers have continued to request, and PacifiCorp has continued to execute, new PPAs since filing its Application. Since May 21, 2015, PacifiCorp has executed 20 PPAs with an aggregate capacity of 172 MW. And since the Commission reduced the eligibility threshold for standard pricing and contracts from 10 MW to 3 MW on August 14, 2015,[30] PacifiCorp has received three new QF PPA requests totaling 147 MW. With the extension of the 30 percent federal investment tax credit for several more years, PacifiCorp expects that the level of QF PPA requests to increase, not decline as the intervenors have suggested.

[26] PAC/100, Griswold/12.
[27] PAC/100, Griswold/14.
[28] PAC/100, Griswold/13.
[29] PAC/100, Griswold/13-14.
[30] Order No. 15-241.

Without permanent revisions to the eligibility threshold and fixed-price term, QF development will continue unabated and PacifiCorp's customers will remain exposed to costly fixed-price contracts for unneeded capacity.

B. PacifiCorp's Proposed Three-Year Fixed-Price Term is Consistent with PURPA

1. A shorter fixed-price term will result in more accurate avoided cost prices

The current 15-year fixed-price term favors QF development over accurate avoided cost pricing—a result that conflicts with PURPA and harms both customers and QF developers. The Commission has acknowledged that long-term, fixed-price QF PPAs expose customers to significant price risk.[31] To minimize risk to PacifiCorp's customers, and to ensure that the ratepayer indifference standard is maintained, the Commission should reduce the maximum fixed-price contract term for standard PPAs from 15 years to three years. Modifying the fixed-price contract term is critical to ensuring that resources procured on behalf of retail customers are as low-cost and as low-risk as possible.

Shorter fixed-price terms result in more accurate avoided cost pricing by eliminating the need to base pricing on inherently inaccurate long-term pricing forecasts. Forecasted avoided cost prices inevitably deviate from actual avoided costs, leaving customers exposed to significant pricing risk.[32] Undisputed record evidence demonstrates the harm that customers suffer when long-term prices deviate from actual avoided costs—over the next ten years, Oregon customers are expected to pay over $320 million more for QF output as compared to average forward prices at the Mid-Columbia trading hub.[33]

---

[31] See, e.g., Order No. 05-584 at 20 ("We acknowledge that 20 years is a significant amount of time over which to forecast avoided costs. Indeed, divergence between forecasted and actual avoided costs must be expected over a period of 20 years").
[32] PAC/100, Griswold/26; PAC/100, Griswold/46.
[33] PAC/100, Griswold/29.

A three-year fixed-price term will not eliminate PacifiCorp's must-purchase obligation. PacifiCorp will remain obligated to enter into new and renewed PPAs with eligible QFs. But a three-year fixed price term will help to resolve the pricing risk that customers are current exposed to. Generally speaking, fixed prices cannot be reset during the term of a PPA, so neither utilities nor QFs have any practical ability to modify prices to reflect current market conditions. But shorter fixed-price terms will allow avoided costs prices to be reset more frequently, which allows for more accurate pricing to be included in new and renewed PPAs. Frequently reset contract prices that reflect current market conditions benefit customers *and* QFs equally—during times of declining prices, customers do not bear the risk of over-market purchase; and during times of rising prices, QFs can capture the full value of their generation. As such, PacifiCorp's proposed three-year fixed-price term is consistent with the Commission's oft-repeated mandate that its primary responsibility when implementing PURPA is to ensure accurate avoided cost prices.[34]

2. Harm associated with long-term fixed-price PPAs is exacerbated by the fact that they are purchased without regard to basic resource planning principles

The recent onslaught of requests for long-term, fixed-price QF contracts belies the fact that the Company must acquire output without regard to basic resource planning principles, including an assessment of the need for new long-term resources. The Company's 2013 IRP, which until the recent filing of the 2015 IRP was the reference for avoided costs in Oregon, included a combined cycle combustion turbine (CCCT) gas plant in 2024.[35] Due to the timing of the identified need for this resource, the 2013 IRP action plan did not include any action items to procure this long-term resource. The 2013 IRP Update,

[34] *See, e.g.,* Order No. 05-584 at 19 ("A primary goal in this proceeding is to accurately price QF power.").
[35] PAC/100, Griswold/11.

filed with the Commission in March 2014, pushed the CCCT out to 2027.[36] Again, due to the timing of this identified need, the Company did not develop an action item to procure this long-term resource.

The Company's 2015 IRP has now been filed with the Commission. The 2015 IRP preferred portfolio pushes the CCCT out even further to 2028 and does not include any action items to procure this long-term resource.[37] Despite the fact that new resources are not needed until next decade, the Company and its customers are now faced with an ever-expanding queue of long-term, fixed-price PPAs. When fixed prices deviate from actual avoided costs (as they inevitably do under a 15 year PPA), customers are harmed by paying QFs more for power than the avoided costs they are entitled to.

3. Shorter fixed-price terms will not stifle QF development

QF intervenors and Staff argue that a longer fixed-price term is necessary to ensure that QFs can secure financing.[38] These concerns are misplaced. PURPA does not expressly state that fixed-price terms must be set at a level to ensure that QFs can obtain financing, and the statute's central principal (that utilities must purchase output from QFs at avoided cost prices) is silent as to the financial viability of QF projects.

QF intervenors argue that a three-year term would make financing impossible.[39] This argument ignores the true nature of PURPA's must-purchase mandate. Under its proposal, PacifiCorp would still be required to purchase a QF's output via an initial three-year term. PacifiCorp would also be required to contract for additional three-year terms through the

---

[36] PAC/100, Griswold/11.
[37] PAC/100, Griswold/11-12.
[38] *E.g.*, Staff/100, Andrus/8-9; CREA/100, Skeahan/6.
[39] *Id.*

QF's useful life. PURPA's must-purchase construct guarantees that utilities will remain obligated to purchase output from viable QF generators beyond the initial three-year term.

The Oregon Department of Energy's (ODOE) testimony notes that sequential three-year financing contracts over the life of any asset are preferred by financiers and are not unusual.[40] While sequential three-year financing contracts may impose a risk premium, ODOE's testimony indicates that financing would not be impossible with a three-year term.[41] Furthermore, PacifiCorp's unrebutted record evidence demonstrates that the development of new financing vehicles such as yieldcos has presented new financing structures and opportunities that would allow for project financing even with reduced fixed-price terms.[42]

Furthermore, QF intervenors and Staff mistakenly testify that PacifiCorp's proposed term changes, combined with the demise of a federal 30 percent investment tax credit (ITC), will make it difficult to develop new solar projects.[43] Congress, however, recently passed a bill that renewed the ITC for solar projects as part of a larger omnibus spending and tax package.[44] The ITC for solar projects will remain at 30 percent for qualifying projects for which construction begins before January 1, 2020. While the ITC had not been renewed at the time testimony was filed, the subsequent extension renders intervenors' and Staff's concerns about project development moot.

]

[40] ODOE/100, Hobbs/2.
[41] ODOE/100, Hobbs/2 ("The proposed reduction to the standard contract length could introduce an additional five or six potential re-pricing events into the term of a traditional commercial loan, provided the use of a three year pricing contract is continued. This level of potential revenue volatility is not unusual in industry per se as the productivity of most pieces of financed equipment is subject to open market forces.")
[42] PAC/100, Griswold/40-41; PAC/200, Griswold/8.
[43] *See, e.g.*, OBSIDIAN AND CYPRUSS CREEK/200, Brown/10; STAFF/100, Andrus/15.
[44] *See* HR 2029, the Military Construction and Veterans Affairs and Related Agencies Appropriations Act, 2016 (the Act).

4. The current 15-year fixed price term is inconsistent with PacifiCorp's Commission-approved hedging policies

The Company has no control over the price risk associated with long-term, fixed-price PPAs; it must purchase essentially an unlimited quantity of QF power under terms and conditions the Commission controls. Under PURPA, only the Commission can mitigate this price risk to customers. In any other context, it is very unlikely that the Commission would sanction long-term resource acquisitions with a similar unavoidable pricing risk.

The current 15-year fixed-price terms conflict with the Company's current hedging practices, which are prudently designed to minimize customer exposure to pricing risk.[45] In 2012, PacifiCorp convened a collaborative process to explore the Company's hedging practices.[46] As a result of its work with staff and stakeholders, PacifiCorp reduced its standard hedging horizon from 48 months to 36 months—a position supported by the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon.[47]

The 36 month hedging horizon ensures reliable sources of electric power are available to meet PacifiCorp customers' needs and reduces volatility of net power costs. The only exception to this 36-month limitation was the Company's acquisition of a longer-term natural gas hedge in 2013, under a Request for Proposals that emerged out of the Company's hedging collaborative. This longer-term hedge was subject to extensive internal and external review, due process, and documentation.

In stark contrast with its must-purchase obligations under PURPA, the Company cannot (without specific stakeholder interest and review) enter into a 15-year hedge for the natural gas fuel cost at one of its gas plants.[48] But the Company is mandated to enter into

---

[45] PAC/100, Griswold/19-25.
[46] PAC/100, Griswold/21.
[47] PAC/100, Griswold/21-23.
[48] PAC/100, Griswold/23.

15-year fixed price PURPA contracts in Oregon with a QF who may be displacing or avoiding the operation of that very same gas plant, effectively locking in the price of that output for 15 years. The 15-year QF contract term is inconsistent with the hedging policy put in place as a direct result of input from stakeholders and is harmful to customers.

If a need for long-term resources is identified in an IRP, the Company typically utilizes a rigorous RFP process to acquire any long-term transaction or resource need directed by the IRP action plan.[49] This process often involves extensive input from regulators in the drafting and management of the RFP. In fact, the process often includes independent evaluator review of the process and ultimate results.[50] The Commission's current PURPA policies do not provide customers with similar levels of protection. Utilities must purchase QF output regardless of whether it is the least-cost, least-risk resource. PURPA contracts are not subject to a competitive bidding process akin to an RFP. And PURPA contracts do not receive any meaningful financial analysis or review because the Company's management does not have the discretion to refuse the mandatory purchase obligation. The Company's only recourse is action by the Commission to align QF contracting standards with the manner in which other resources are acquired. Without such changes, customers will remain at risk.

5. A three-year fixed-price term is consistent with the policies of other states where PacifiCorp operates

PURPA delegates to the states broad discretion to set the terms and conditions of PURPA contracts, and there are multiple examples of where states have reduced contract lengths to protect the customer indifference standard.

[49] PAC/100, Griswold/25.
[50] PAC/100, Griswold/25.

For example, the Idaho Public Utilities Commission (IPUC) recently affirmed its August 2015 order that reduced the fixed price term for QF PPAs from 20 years to two years.[51] The IPUC based its conclusions, in part, on the same record evidence PacifiCorp and the QF intervenors have presented in this proceeding.

Recognizing that PURPA is not the most economically efficient option for encouraging renewable generation, the Washington Utilities and Transportation Commission (WUTC) has similarly set five-year fixed price terms for standard QF PPAs.[52]

C. PacifiCorp's Proposed 100 kW Cap for Wind and Solar QFs is Consistent with PURPA

The current 10 MW threshold does not effectively differentiate small and large QFs. The maximum nameplate capacity rating eligible for standard and renewable avoided cost prices under Schedule 37 should be reduced from 10 MW to 100 kW for wind and solar QFs. A 10 MW solar project, requiring approximately 60 acres of land, is not a small project.[53] It requires significant capital expense ranging from $18 million to $24 million.[54] These large solar projects require detailed interconnection studies consistent with Oregon rules and the transmission provider's transmission tariff. The effort needed to develop a 10 MW QF project is no less than the effort needed to develop a 20 MW or even an 80 MW solar project except for possibly the transmission interconnection voltage. Therefore a 10 MW cap is not an effective measure of a small project from a development perspective.

---

[51] In The Matter Of Rocky Mountain Power Company's Petition To Modify Terms And Conditions Of PURPA Purchase Agreements, CASE NO. PAC-E-15-03, Order No. 33357 (IPUC, August 20, 2015); PAC/200, Griswold/6.
[52] PAC/200, Griswold/6. *See also Exelon Wind I LLC*, 766 F.3d 380 (5th Cir. 2014) (Upholding the Texas Commission's decision to limit the long-term pricing available through a legally enforceable obligation to wind farms that could deliver firm power).
[53] PAC/100, Griswold/33.
[54] PAC/100, Griswold/33.

Reducing the eligibility cap will do several things. First, it will help mitigate the large and well-funded out-of-state developers from "pushing aside" the small independent developer for which PURPA standard offer prices and contracts were established.[55] Second, a lower eligibility cap will continue to support the PURPA objective of minimizing transaction costs for genuinely small QFs. Third, a lower cap will ensure that avoided cost rates reflect the project-specific operating characteristics as compared to the proxy resource, whether standard or renewable. And finally, a lower cap will limit the operational impact and cost on distribution and transmission assets in PacifiCorp's rural areas of Oregon that were designed to serve rural loads like pumps and motors, not to handle intermittent generation. Lowering the standard rate and contract eligibility threshold to 100 kW for wind and solar QFs is reasonable in light of recent QF development in Oregon. A 100 kW eligibility cap would continue to reduce market barriers for locally-owned, genuinely small QF projects across all resource types.[56] At the same time, a 100 kW eligibility cap will ensure that project-specific characteristics for wind and solar QFs are captured and reflected in avoided cost prices.[57]

As the eligibility cap has increased over time to the current 10 MW, the Company is now processing Schedule 37 PPA requests submitted by well-funded, experienced developers who are not local, who have successfully developed multiple QF and renewable projects across the country and internationally, and hire some of the most skilled technical and legal firms in the country.[58] It is clear that the vast majority of QF developers are not the small "mom & pop" operations that PURPA was originally intended to encourage and who are less

[55] PAC/100, Griswold/33.
[56] PAC/100, Griswold/33.
[57] PAC/100, Griswold/33.
[58] PAC/100, Griswold/40-41.

exposed to the market barriers the standard PPA threshold is intended to address. Instead, QF projects are currently developed and owned by sophisticated companies backed by sophisticated financing and sophisticated legal representation, often with broad portfolios of renewable generation many of which are being flipped into a recently developed project ownership model called a yieldco for the benefit of investors and at the expense of customers.[59] While market barriers may exist for genuinely small developers, the standard PPA threshold should not be set at a level that encourages development by sophisticated parties who are capable of negotiating accurate avoided cost prices.

To be clear, setting the eligibility threshold to 100 kW will not preclude larger QFs from receiving avoided cost prices. Wind and solar projects over 100 kW (like other larger QFs) will receive avoided cost prices via the Company's negotiated Schedule 38 rate. This will ensure that wind and solar QFs are accurately priced, which will minimize fixed-price risk for the Company's customers (and QFs in times of rising prices). Recent QF PPA requests illustrate this point. Since the Commission reduced the eligibility cap to 3 MW on an interim basis in August 2014, PacifiCorp has received three PPA requests for larger solar projects totally 147 MW.

The alternative eligibility thresholds proposed by Staff and other intervenors fall short of the needed change. Staff has recommended setting the eligibility cap between 2 and 4 MW for wind and solar to incent larger wind projects while protecting small developers from market barriers, and to preventing gaming through disaggregation of larger projects into smaller projects.[60] But setting the solar and wind eligibility threshold to 100 kW will allow project-specific characteristics to be applied to a larger and more appropriate population of

[59] PAC/100, Griswold/41.
[60] STAFF/100, Andrus/19.

QF projects resulting in more accurate avoided cost pricing by allowing avoided costs to reflect a QF's unique characteristics.[61] This will, in turn, help minimize the difference between prices paid to QFs and actual avoided costs, and ensure that customers are indifferent to QF purchases.

D. QFs are not Comparable to Other Utility Resources

Sierra Club mistakenly argues that QF contracts are comparable to the utility-owned generation resources.[62] As detailed above, utility resource acquisitions outside PURPA are subject to a host of protections that ensure selection of least-cost, least-risk resources.[63] QF PPAs provide none of these protections and utilities are forced (to customers' detriment) to purchase QF output even if it is not least-cost, least-risk.

Furthermore, QF resources cannot be dispatched in the same manner as a Company resource.[64] In fact, QFs as must-take obligations cannot be dispatched at all except under system emergency conditions directed by PacifiCorp Transmission grid operations.[65] The lack of dispatchability comes at an expense for customers. For example, if the marginal cost of a Company gas plant is $40 per MWh, but another alternative, such as a short-term firm market purchase, costs only $30 per MWh, the Company would dispatch down the gas plant and buy from the market, saving customers $10 per MWh. QFs present a completely different (and more costly) scenario. If a QF contract has a $40 per MWh price, but another alternative costs $30 per MWh, the Company cannot curtail or dispatch down the QF

---

[61] PAC/200, Griswold/20-21.
[62] SIERRA CLUB/100/McGuire/12-13.
[63] PAC/100, Griswold/25.
[64] PAC/200, Griswold/14.
[65] PAC/200, Griswold/14.

contract – it must continue to purchase the output at $40 per MWh even though a less expensive alternative exists.[66]

Sierra Club also mistakenly argues that QFs retain significant performance risk in the event that a project is not built or does not generate.[67] While QFs do retain some risk, PacifiCorp's customers also face significant risk from QFs. The QF contract is a resource used to serve Company network load, it is being counted in its load and resource balance, the Company has acquired network transmission to move that QF generation to load, and if the QF does not generate, the Company would need to secure replacement power, having incorporated expected generation from the QF resource in its system position, to the detriment or benefit of the customer.[68] The difference with a Company resource is the control of the resource, both on performance and operation. Additionally, Company resources are not guaranteed a specified rate of return through the life of the asset. Company resources face review during each rate case and are subject to changes in the Company's allowed rate of return, multi-state allocation protocol issues, and other such cost recovery risks.[69]

IV. CONCLUSION

For the reasons set out above, PacifiCorp respectfully requests that the Commission grant the relief PacifiCorp seeks in its Application.

Respectfully submitted this 5th day of January, 2016.

By:____________________________
Dustin Till
Senior Counsel
PacifiCorp d/b/a Pacific Power

---

[66] PAC/200, Griswold/14.
[67] SIERRA CLUB/100, McGuire/12-13.
[68] PAC/200, Griswold/15.
[69] PAC/200, Griswold/15.