PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

May 21, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

RE: Docket UM ____
PacifiCorp's Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap

PacifiCorp d/b/a Pacific Power submits for filing its Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap.

It is respectfully requested that all formal data requests to the Company regarding this filing be addressed to the following:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Please direct informal inquiries to Erin Apperson, Regulatory Affair Manager at (503) 813-6642.

Sincerely,

R Bryce Dalley / HCS

R. Bryce Dalley
Vice President, Regulation

Enclosures

CC: UM 1610 Service List
UM 1725 Service List

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM _____

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 APPLICATION**

I. INTRODUCTION AND SUMMARY

PacifiCorp d/b/a/ Pacific Power (the Company or PacifiCorp) respectfully submits this Application to Reduce the Qualifying Facility (QF) Contract Term and Lower the QF Standard Eligibility Cap under ORS 758.535(2) and OAR 860-001-0400(2). In this petition, the Company specifically asks the Public Utility Commission of Oregon (the Commission) to:

1. Reduce the fixed-price term of QF power purchase agreements (PPAs) from 15 years to three years; and
2. Lower the eligibility cap for standard QF pricing and PPAs from 10 megawatts (MW) to 100 kilowatts (kW) for wind and solar QFs.

PacifiCorp recognizes that the Commission affirmed the 10 MW eligibility cap in Order No. 14-058 in Phase I of docket UM 1610. PacifiCorp also acknowledges that the Commission did not revisit the 15-year fixed price term, which was briefed by the parties, in Phase I of UM 1610.

PacifiCorp, however, has experienced a striking increase in requests for new long-term QF PPAs since the Commission issued Order No. 14-058 in February 2014. Since that time, the Company has executed 104 MW of new Oregon QF PPAs. The Company now has 338 MW of executed QF PPAs in Oregon, and another 587 MW in active requests for Oregon QF PPAs. The 925 MW of existing and proposed PURPA contracts in Oregon at their nameplate capacity would be enough to supply 56 percent of the Company's average Oregon retail load and 90 percent of the Company's minimum Oregon retail load.

When PacifiCorp's six-state system is taken into consideration, the increase in QF PPA requests is more dramatic. PacifiCorp currently has requests for 4,017 MW of new PURPA contracts system-wide. That amount is in addition to the 1,991 MW of QF contracts that are executed and operating or under construction. The 6,008 MW of executed and proposed PURPA contracts at their nameplate capacity would be enough to supply 88 percent of PacifiCorp's average retail load and 121 percent of PacifiCorp's minimum retail load.

The dramatic increase in executed and proposed QF PPAs, combined with 15-year fixed price terms, has exposed 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. 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. 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. 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.

The discrepancy between average contracted-for avoided cost prices and market prices illustrates the significant price risk the Company's customers are exposed to. The Company currently has 145 PURPA contracts totaling 1,991 MW of nameplate capacity across its six-state system. Oregon's allocated share of these contract costs averages approximately 25 percent. Over the next ten years, the Company is under contract to purchase 44.6 million MWh under its PURPA contract obligations at an average price of $64.13 per MWh. The average forward price curve for Mid-C for this same ten years is $35.27 per MWh,[1] or a difference of $28.86 per MWh. Thus, PacifiCorp's customers would be expected to pay over $1.2 billion more than current market prices over the next ten years on a system-wide basis, and Oregon customers would be expected to pay over $320 million more.

PacifiCorp's 2015 Integrated Resource Plan (IRP) shows that additional resources (either thermal or renewable) are not needed until 2028. The Company's long-term resource acquisitions, when necessary, are subject to controls that protect customers from price risk by ensuring the selection of lowest-cost and least-risk resources. The Company's risk policies limit hedging transactions to 36 months in order to protect customers. The Company does not enter into long-term transactions unless the IRP preferred portfolio identifies the need for long-term resources. Furthermore, the Company's long-term resource acquisitions are thoroughly evaluated via the Commission's request for proposal (RFP) process.

The Company's QF purchase obligations, however, are not subject to similar customer protection controls. The Company must purchase, and its customers must bear the cost of, QF output at prices fixed for 15 years without any regard to whether the output is needed or is the least-cost, least-risk option.

PacifiCorp's petition to lower the fixed-price contract term from 15 years to three years and reduce the standard price eligibility threshold for wind and solar QFs from 10 MW to 100 kW is supported by the direct testimony of Mr. Bruce W. Griswold, including several exhibits and other supporting information.

[1] Based on a May 1, 2015, forward price curve for a 7x24 (flat) electricity product.

II. NOTICE

Communications regarding this Application should be addressed to:

R. Bryce Dalley
Vice President, Regulation
Pacific Power
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232
Email: bryce.dalley@pacificorp.com

Dustin T. Till
Senior Counsel
Pacific Power
825 NE Multnomah Street, Suite 1800
Portland, Oregon 97232
Email: dustin.till@pacificorp.com

Oregon Dockets
Pacific Power
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232
Email: OregonDockets@pacificorp.com

In addition, the Company asks that all data requests regarding this application be sent to the following:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

III. BACKGROUND AND LEGAL CONTEXT

A. PURPA

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.[2] 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 against QFs, and (3) do not exceed "the incremental cost to the electric utility of alternative electric energy."[3] The

[2] *See, e.g.,* 16 U.S.C. § 2601 (Findings).
[3] 16 U.S.C. § 824a-3.

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.[4] 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.[5]

In 1980, FERC issued rules implementing PURPA that included a utility's "avoided costs" as the standard for implementing the incremental cost requirement.[6] 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.[7]

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:

---

[4] 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.

[5] *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.")

[6] *See American Paper Inst. v. American Elec. Power Serv.*, 461 U.S. 402, 406 (1982) (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 § 210(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).

[7] *Idaho Power Co. v. Idaho Pub. Util. Comm'n.*, 155 Idaho 780, 782 (2013) ("*Idaho Power Co.*")(citing *FERC v. Mississippi,* 456 U.S. 742, 751 (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.[8]

The Commission has repeatedly acknowledged the importance of ratepayer indifference when setting PURPA policies.[9] Indeed, the Commission has identified ratepayer indifference as its "primary aim."[10]

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."[11] 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.[12]

The modifications requested by the Company in this petition 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.

---

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

[9] *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 PURP A policies continue to promote QF development while ensuring that utilities pay no more than avoided costs.")

[10] 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.")

[11] *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).

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

B. The Commission is Authorized to Determine the Appropriate Contract Term for Qualifying Facilities to Receive Under PURPA

Although PURPA's federal mandate requires utilities to purchase QF power, PURPA's scheme of cooperative federalism gives state regulatory agencies the authority to protect 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.[13]

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."[14] While FERC has created the abstract framework for the application of PURPA through its regulations, FERC has left it to the states to determine the specific details of how such contracts will be executed.[15] 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."[16]

A critical element of the utility's must-purchase requirement under PURPA is the contract term. This is because FERC generally requires a utility to lock in forecasted avoided

---

[13] Order No. 14-058 at 3; *Exelon Wind I, LLC*, 766 F.3d 380, 394-95 (5th Cir. 2014).

[14] 18 C.F.R. § 292.304(d)(2).

[15] *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.")

[16] *Cal. Pub. Util. Comm'n,* 133 FERC ¶ 61,059 at P 24 (2010).

cost rates for the entire contract term.[17] FERC has explained that it believes imperfections found in the avoided cost methodology should, if set correctly, balance out between overestimation and underestimations.[18] However, PURPA and FERC regulations are silent as to the length of QF contracts and, with a few exceptions not relevant here,[19] FERC has not spoken directly to the issue of setting an appropriate contract length.

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.[20] 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]."[21] 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 the terms of QF contracts to five years. On October 30, 1996, PGE filed

---

[17] *See Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA*, 45 Fed. Reg. 12214, 12224 (1980).

[18] *Id.*

[19] For example, FERC has stressed a need for certainty with regard to return on investment in new technologies and for allowing for varying contract lengths based on other contract factors. *See, e.g.*, *Cal. Pub. Util. Comm'n,* 133 FERC ¶ 61,059.

[20] *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.").

[21] *Exelon Wind I, LLC*, 766 F.3d at 396.

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.

The Commission Staff in their memo to the Commission noted "[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.[22] The Commission adopted PGE's filing at their 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 limits 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."[23] 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.

---

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

IV. ARGUMENT

A. PacifiCorp's Request to Reduce the Fixed-Price Term of QF PPAs From 15 Years to Three Years.

1. The Dramatic Rise in Fixed-Price PPA Requests

Increasing levels of QF generation are exposing customers to progressively higher levels of risk, warranting immediate Commission action to protect customers. The Commission has acknowledged that long-term, fixed-price QF PPAs expose customers to significant price risk.[24] To minimize risk to PacifiCorp's customers, and to ensure that the ratepayer indifference standard is maintained, the Commission should permanently 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.

The Company has experienced a dramatic increase in QF pricing requests since the Commission affirmed the 20 year contract term in Order No. 14-058. Since that order was published on February 24, 2014, the Company has executed 104 MW of Schedule 37 QF contracts in Oregon, and the Company now has 338 MW of QF capacity in Oregon. And requests for new Schedule 37 QF PPAs have continued unabated. Indeed, as of May 1, 2015, the Company has received 25 pending requests for QF PPAs seeking fixed-price terms totaling 587 MW in Oregon.

The magnitude and potential impact of this increased PURPA activity is best measured by comparing the total amount of existing and proposed Oregon PURPA projects to the Company's Oregon retail load. Using 2014 as an example, the Company's average total Oregon retail load was 1,661 MW and its minimum total Oregon retail load was 1,027 MW. The 925

---

[24] *See, e.g.*, Order No. 05-584 at 20 ("[W]e 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").

MW of existing and proposed PURPA contracts in Oregon at their nameplate capacity would be enough to supply 56 percent of the Company's average Oregon retail load and 90 percent of the Company's minimum Oregon retail load.

Expanding the analysis to the Company's six-state system, PacifiCorp currently has requests for 4,017 MW of new PURPA contracts system-wide, in addition to the 1,991 MW of QF contracts that are executed and operating or under construction. In 2014, the Company's maximum system-wide retail load was 10,314 MW, its average system-wide retail load was 6,844 MW, and its minimum system-wide retail load was 4,967 MW. The 6,071 MW of existing and proposed PURPA contracts at their nameplate capacity would be enough to supply 88 percent of the Company's average retail load and 121 percent of the Company's minimum retail load.

2. The Company Has No Current Need for System Resources

The recent onslaught of requests for long-term, fixed-price QF contracts belies the fact that the Company has no 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 Utah, included a combined cycle combustion turbine (CCCT) gas plant in 2024. 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, filed with the Commission in March 2014, pushed the CCCT out to 2027. 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. Despite the fact that new resources are not needed until next decade, the Company and its customers now faced with an ever-expanding queue of long-term, fixed-price PPA requests.

3. Potential Impact of QF Contracts on Customers

The expected system-wide costs (payments to QFs) over the next ten years from PacifiCorp's total executed PURPA contracts is $2.9 billion. In 2015 alone, the projected payment to QFs is $170.5 million, with Oregon's allocated share at $42.6 million. If QF projects are priced higher than the market alternative by just 10 percent, it would create a $4.3 million impact in 2015 for Oregon customers. That 10 percent impact would grow to a total of $72.5 million in additional costs to Oregon customers over the ten-year period starting in 2015.[25] With 4,017 MW in pending Schedule 37 PPA requests system-wise, or close to double (in MW) the size of the $2.9 billion worth of current PURPA contracts to which the Company is already obligated, it is imperative that customers be protected from the long-term, fixed-price risk that comes with a 15-year or longer contract term for QFs. If the Commission declines to lower the standard QF PPA fixed-price term from 15-years to three years, the Company' customers will continue to be exposed to unreasonable fixed-price risk.

4. 15-Year Fixed-Price QF PPAs are Inconsistent with the Company's Hedging and Contracting Policies.

The current 15-year fixed-price term of QF PPAs grants QFs something no other market participant enjoys: long-term pricing certainty with no pricing adjustments. This facet of QF

[25] Electricity and natural gas markets have fallen dramatically in the past year as oil prices have also declined. On August 1, 2014, a ten-year fixed-price contract for a seven-day by 24-hour electricity product at the Mid-Columbia wholesale power market trading hub was priced at $45.87 per MWh. On May 1, 2015, just twelve months later, that same ten-year contract was priced at $35.27 per MWh. The ten-year electricity market declined 23 percent in just twelve months. Hypothetically, had the Company purchased 100 MW of this ten-year fixed-price electricity on August 1, 2014 at $45.87 per MWh, just twelve months later the Company would have a nominal mark-to-market loss of $93.0 million on the contract.

PPAs is inconsistent with the Company's (and the energy industry's) hedging practices and the manner in which it enters into long-term transactions.

In the wake of its 2012 TAM filing, and a subsequent Commission workshop, the Company announced its intention to reduce its standard hedging time horizon from 48 months to 36 months—a position that was supported by the Citizens' Utility Board or Oregon and the Industrial Customers of Northwest Utilities. PacifiCorp's hedging horizon is consistent with industry practices, where the contracting and hedging horizons for energy contracts are commonly limited to less than 36 months. Indeed, it is extremely rare for a utility to voluntarily enter into a 15-year fixed-price energy contract due to concerns about price risk, market liquidity, and other risk considerations.

The Company primarily enters into long-term transactions (those that exceed 36 months) only when there is a clearly identified long-term resource need in its IRP. Long-term resource needs are typically identified in the IRP only after lower-cost, lower-risk short-term resource opportunities are exhausted such that a long-term resource is required to meet customer load requirements. And the Company typically utilizes a rigorous request for proposal (RFP) process to acquire long-term transactions or resources identified in an IRP action plan. In fact, if the resources or transaction involves generating resources that produces 100 MW or more and has a term of ten years or more, the Company is required to go through the exhaustive RFP process to ensure the lowest possible cost.[26]

Under the Commission's current PURPA policies, however, any QF can obtain a 15-year, fixed-price energy contract at the Company's projected avoided cost, without any economic considerations or price adjustment to account for the risk to utility customers from this unusually

[26] *See* Docket No. UM 1182, Order No. 06-446 at 2 (Aug. 10, 2006) (A utility must issue an RFP for all Major Resource acquisitions identified in its last acknowledged IRP. Major Resources are resources with durations greater than 5 years and quantities greater than 100 MW.)

long-term transaction, or to the QF to account for the price certainty the QF enjoys from such a contract.

5. Other Jurisdictions Have Implemented Shorter Fixed-Price Terms to Protect Utility Customers.

Other jurisdictions in PacifiCorp's six-state service territory have recognized that shorter fixed-price terms are necessary to protect utility customers. Most recently, the Idaho Public Utilities Commission (the Idaho Commission) addressed the need to reduce QF contract terms to protect ratepayer neutrality. In response to the magnitude of QF power flowing onto utilities' systems without any finding of need and associated concerns about price risk, reliability, and ratepayer indifference, the Idaho Commission reduced the term of fixed-price PURPA contracts for the Company, Idaho Power and Avista to five years for solar and wind QF projects larger than 100 KW pending completion of a docket considering a permanent reduction to the PPA term.[27]

Idaho is not alone in limiting the fixed-price term of QF PPAs. The Washington Utilities and Transportation Commission (WUTC) has limited the fixed price term of PacifiCorp's standard QF PPAs to five years.[28] And on May 11, 2015, the Company petitioned the Public Service Commission of Utah to reduce the term of standard, fixed-price PPAs from 15 years to three years.

---

[27] Case No. IPC-E-15-01, Order No. 33222 (Ida. PUC Feb. 6, 2015) (Idaho Power), Order No. 33250 (Id. PUC Mar. 13, 2015) (Rocky Mountain Power and Avista), and Order No. 33253 (Ida. PUC Mar. 18, 2015) (clarifying that the interim reduction applies to QF projects that exceed the published rate eligibility cap (up to 100 KW for solar and wind and up to 10 average megawatts (aMW) for QFs of all other resource types).

[28] *See* PacifiCorp's Washington Schedule 37, Terms and Conditions No. 7 (fixing avoided costs for five years), *available at* https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Washington/Approved_Tariffs/Rate_Schedules/Cogeneration_and_Small_Power_Production.pdf.

B. PacifiCorp's Request to Lower the Standard Eligibility Cap for Wind and Solar QFs from 10 MW to 100 kW.

1. Background

PURPA expressly contemplates that standard rates and contract terms should apply to very small projects or those under 100 kW in order to minimize transactions costs that might otherwise keep the projects from going forward. In its order implementing the PURPA regulations, FERC stated:

> The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rates required by this 12 paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standard tariffs be implemented for facilities 100 kW or less.[29]

This Commission has repeatedly explained that the eligibility threshold "should be set at a level no higher than necessary to overcome market barriers associated with transaction costs."[30] To that end, the threshold for standard rate eligibility has never been static. In 1981, the Commission initially set the threshold at 100 kW consistent with FERC's regulations.[31] The threshold was increased to 1 MW in 1991.[32] The Commission established the current 10 MW cap in 2005, based on its concerns about potential market barriers and transaction costs.[33] The Commission, however, has been mindful of the PURPA "ratepayer indifference" standard when setting eligibility thresholds, stating that:

> [W]e recognize a need to 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. With standard contracts, project characteristics that

[29] FERC, 18 CFR Part 292, Docket RM79-55, Order No. 69.
[30] Order No. 05-584 at 16.
[31] Order No. 81-319 at 4 ("Standard rates should be available only to facilities of 100 kW or less.")
[32] Docket No. AR 246, Order No. 91-1605 (Nov. 26, 1991).
[33] Order No. 05-584 at 1.

cause the utility's cost savings to differ from its actual avoided costs are ignored.[34]

The Commission's concerns about market barrier have been rendered moot by the changing nature of QF development in Oregon. The current 10 MW cap is no longer encouraging development by local, genuinely small businesses. Instead, sophisticated and well-financed out-of-state developers are taking advantage of the 10 MW threshold to earn maximum returns for investors at the expense of the Company's Oregon customers. The Commission has the discretion to establish a standard price eligibility threshold that encourages *small* QF development while ensuring ratepayer indifference.

2. 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. It requires significant capital expense ranging from $18 million to $24 million. 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 any effective measure of a small project from a development perspective.

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.[35] Second, a lower

---

[34] Order No. 05-584 at 16.

[35] The Company is experience an increasing volume of PPA requests from sophisticated out-of-state developers. For example, between March and August 2014, the Company received 33 Schedule 37 PPA requests. Twenty-five

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. 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.

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. 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 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 yield cos

---

of those requests were from developers located outside the Pacific Northwest. From mid-April 2015 through mid-May 2015, the Company has received 13 Schedule 37 PPA requests totaling 119 MW from three developers, two of which are national and international developers. Of the thirteen projects, ten are being proposed at the 10 MW maximum.

for the benefit of investors and at the expense of customers. 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.

3. Lowering the Eligibility Cap to 100 kW Will Protect Customers by Ensuring More Accurate Avoided Cost Prices for Wind and Solar QFs.

As detailed above, avoided cost rates must comply with the "ratepayer indifference" standard, and a utility's avoided costs are the *maximum* rate that may be prescribed.[36] Standard rates are, at best, an approximation of a utility's avoided cost. Indeed, the Commission has recognized that standard rates can result in prices that exceed actual avoided costs.[37]

Few, if any, of the QF resources eligible for Schedule 37 avoided cost prices produce energy that provides equivalent value to the proxy resource energy. Most QF resources receiving Schedule 37 avoided cost prices are, to some degree, receiving incremental value based on the difference between the operating characteristics of the QF resource and the proxy plant, and therefore do not always reflect the true avoided cost to the utility. Furthermore, standard

[36] *American Paper Institute,* 461 U.S. at 413; Order No. 14-058 at 12 ("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*.") (emphasis added)
[37] Order No. 14-058 at 7 ("[A]pplication of our current methodology may result in the utility and its customers offering prices in excess of actual avoided costs.")

prices do not reflect the incremental cost associated with adding a new QF to PacifiCorp's system.

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 QF projects. In fact, FERC's and the Commission's regulations make clear that project-specific factors must be taken into consideration when avoided cost prices are set.[38] This will result in more accurate avoided cost pricing by allowing avoided costs to reflect a QF's unique characteristics (for example, the costs associated with integrating remote, intermittent generating resources with low capacity factors). 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.

V. CONCLUSION

For the reasons detailed herein, PacifiCorp asks the Commission to issue an order directing the Company to implement the following changes to its PURPA contracting procedures: (1) reduce the fixed-price term of QF PPAs from 15 years to three years; and (2) reduce the eligibility threshold for standard PPAs and pricing from 10 MW to 100 kW for solar and wind QFs. These changes will allow for continued QF development in Oregon while minimizing customer risk to long-term fixed price PPAs and ensuring that QF output is priced consistent with PURPA's "ratepayer indifference" standard.

Respectfully submitted this 21st day of May, 2015.

Dustin T. Till
Senior Counsel
PacifiCorp d/b/a Pacific Power

[38] 18 C.F.R. § 292.304(e); OAR 860-029-0040(5).

Docket No. UM ___
Exhibit PAC/100
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Bruce W. Griswold

May 2015

TABLE OF CONTENTS

QUALIFICATIONS 1
Background 6
PURPA and the Ratepayer Indifference Standard 6
PacifiCorp has Experienced a Significant Increase in Schedule 37 PPA Requests 10
The Company's Oregon PURPA Contracts Will Result in Higher Customer Rates, in Conflict with the Ratepayer Indifference Standard 12
THE COMMISSION SHOULD REDUCE THE FIXED-PRICE CONTRACT TERM FROM 15-YEARS TO THREE YEARS. 14
15-YEAR PURPA CONTRACTS ARE INCONSISTENT WITH CURRENT HEDGING PRACTICES AND RISK POLICIES 19
Long-Term Resource Planning: PacifiCorp's IRP Process and Current Resource Needs 29
ELIGIBILITY CAP FOR OREGON SCHEDULE 37 32
CONCLUSION 44

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Bruce W. Griswold. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am employed by Pacific Power as Director of Short-Term Origination and Qualifying Facility (QF) Contracts.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I have a B.S. and M.S. degree in Agricultural Engineering from Montana State University and Oregon State University, respectively. I have been employed by the Company for over 25 years in various positions of responsibility in retail energy services, engineering, marketing and wholesale energy services. I have also worked at an environmental firm as a project engineer.

My current responsibilities as Director of Short-term Origination and QF Contracts include the negotiation and management of wholesale power supply and resource acquisition through requests for proposals (RFP) as well as responsibility for the Company's QF power purchase agreements (PPA). I have appeared as a witness on behalf of the Company in multiple proceedings across its six state jurisdictions.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support and present the Company's application to modify two conditions of QF contracts that the Company must enter into under the Public Utility Regulatory Policies Act of 1978 (PURPA). First, the Company is seeking to lower the maximum allowable fixed-price contract term of QF contracts executed under both Oregon Schedules 37 and 38. Second, the Company is seeking to reduce the nameplate capacity of QF projects eligible for Oregon Schedule 37 QF contracts.

These changes are necessary to maintain the "ratepayer indifference" standard required by PURPA. Specifically, the Company is requesting an order from the Public Utility Commission of Oregon (Commission) directing implementation of (1): a reduction of the maximum fixed-price contract term for PURPA contracts from 15 years to three years, to be consistent with the Company's hedging and trading policies and practices for non-PURPA energy contracts and more aligned with the Integrated Resource Plan (IRP) cycle; and (2) a reduction in the eligible nameplate capacity cap for Schedule 37 from 10 megawatts (MW) to 100 kilowatts (kW) for wind and solar QF projects.

The Company understands that the Commission reaffirmed the 10 MW eligibility cap in Phase I of UM 1610.[1] However, since the Commission issued Order No. 14-058 in Phase I of UM 1610 on February 24, 2014, the Company's circumstances have drastically changed in Oregon and across its six-state system, necessitating that the Commission revisit its decision. The Company currently has 338 MW[2] of executed PURPA contracts in Oregon and 587 MW of active[3] proposed PURPA contracts in Oregon, together totaling 925 MW of nameplate capacity. Since the issuance of Order No. 14-058, the Company has executed 104

[1] Docket No. UM 1610, Order No. 14-058 at 7-8 (Feb. 24, 2014).
[2] Unless specifically noted, values in my testimony are rounded to the nearest full MW.
[3] Active for the purpose of my testimony means a proposed QF PPA request where the developer and PacifiCorp are still in engaged in the Schedule 37 or 38 procedures.

MW of new Schedule 37 QF PPAs for projects that are currently under development or being constructed, including 74 MW of new solar QF contracts. During the same period, the number of projects seeking new QF contracts has grown significantly.

Table 1 summarizes the capacity of QF projects that have requested or executed fixed-price PPAs under Oregon Schedule 37 and Schedule 38, and demonstrates the stark growth in fixed-price PPA requests in Oregon.

Table 1

Oregon QF	Pre- 2014 (MW)	2014 (MW)	2015* (MW)	TOTAL (MW)
Executed – Schedule 37	234	104		338
Requested – Schedule 37		199	199	398
Requested – Schedule 38		109	80	189
TOTAL	**234**	**412**	**279**	**925**

*Through May 1, 2015

My testimony describes the significant increase in QF activity since 2014, how this growth in activity increases risk to customers, and why the requested modifications to the avoided cost contract term for all QFs and eligibility cap for Schedule 37 wind and solar projects are needed.

The magnitude and potential impact of this increased PURPA activity is best measured by comparing the total amount of existing and proposed Oregon PURPA projects to the Company's Oregon retail load. Using 2014 as an example, the Company's average total Oregon retail load was 1,661 MW and its minimum total Oregon retail load was 1,027 MW. The 925 MW of existing and proposed PURPA contracts in Oregon at their nameplate capacity would be enough to supply 56 percent of the Company's average Oregon retail load and 90 percent of the Company's minimum Oregon retail load. Expanding the analysis to the

Company's six-state system, PacifiCorp currently has requests for 4,017 MW of new PURPA contracts system-wide, in addition to the 1,991 MW of QF contracts that are executed and operating or under construction. Thus, PacifiCorp's total PURPA obligation would be 6,008 MW if all the proposed PPAs are executed.

Q. How is your testimony organized?

A. First, I provide testimony in support of the Company's request to reduce the 15-year fixed price contract term to a three year fixed price term. I explain and illustrate how the current requirement to fix prices for up to a 15-year contract term is: (1) inconsistent with changes to the Company's hedging practices implemented after litigation in Docket No. UE 227, the 2012 Transition Adjustment Mechanism (2012 TAM), and a subsequent collaborative process; (2) inconsistent with resource acquisition policies and practices for non-PURPA energy purchases; and (3) not aligned with the Company's IRP planning cycle and action plan. I provide evidence demonstrating the impact of PURPA contracts on customers' rates as a result of the current 15-year fixed-price term. I also describe how, without the requested modification to contract term, PacifiCorp will be forced to continue to acquire long-term, fixed-price PURPA contracts even though PacifiCorp's 2015 IRP, which was filed in March 2015, shows no new generating resource, either thermal or renewable, is required until 2028.

Second, I explain and provide examples of why the nameplate capacity of solar and wind projects eligible for standard fixed prices under Schedule 37 should be reduced from 10 MW to 100 kW by demonstrating that: (1) the current development community for Schedule 37 QF projects are no longer the small independent "mom and pop" developers but large, well-funded, and sophisticated developers including national and international leaders in renewable project development; and (2) a 10 MW eligibility threshold for Schedule 37 increases cost risk to customers especially when combined with a 15-year term fixed price contract.

Q. Why is the requested modification critical at this time?

A. PacifiCorp routinely reviews PURPA contract terms and conditions and avoided cost methods, and recent events dictate that the Company petitions this Commission for two changes at this time.

The Company has recently experienced a significant increase in QF pricing requests in Oregon and across its six-state system. The recent spike in QF activity comes at a time when the Company has no need for new generating resources through the next decade. Moreover, the Company's hedging practices and policies are short-term in nature. In response to stakeholder feedback in the 2012 TAM and a subsequent collaborative process in Oregon and other states, the Company reduced its standard hedging horizon from 48 months to 36 months.

Given the magnitude of new Schedule 37 QF requests (primarily wind and solar), and considering the inherent uncertainties in projecting avoided cost rates out 15 years or more, current Oregon avoided cost rates expose customers to unreasonable fixed-price risk for 15 years (or longer).[4] To protect customers from this risk on an on-going basis, the Company asks the Commission to reduce the

[4] While fixed prices are currently limited to a maximum 15-year term, Oregon avoided cost prices are only updated annually and can be locked down years before a project's expected commercial operation date. This introduces fixed price exposure risk well beyond the 15-year fixed price contract term.

maximum contract term for PURPA contracts from 15 years to three years. A three-year fixed price term is consistent with the Company's hedging and trading policies and practices for non-PURPA energy contracts and more aligned with the IRP cycle.

The Company also asks the Commission to reduce nameplate capacity eligible for Schedule 37 from 10 MW to 100 kW for wind and solar. Such a request remains consistent with PURPA's federal provisions and utility obligations for standard offer contracts and pricing. My testimony explains how the current 10 MW cap is not encouraging QF development, but instead, is allowing relatively large projects (up to 10 MW) by sophisticated, out-of-state developers to obtain long-term fixed-price contracts that do not reflect the actual cost to PacifiCorp's customers.

BACKGROUND

PURPA and the Ratepayer Indifference Standard

Q. Describe the history and purpose of PURPA.

A. 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.[5] PURPA requires electric utilities to purchase all electric energy made available by QFs at rates that: (a) are just and reasonable to electric consumers; (b) do not discriminate against QFs; and (c) do not exceed "the

[5] *See, e.g.,* 16 U.S.C. § 2601 (Findings).

incremental cost to the electric utility of alternative electric energy."[6] 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.[7]

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 otherwise incur in the absence of the QF purchase.[8]

In 1980, FERC issued rules implementing PURPA in which it adopted what it called a utility's "avoided costs" as the standard for implementation of the

---

[6] The provisions of 16 U.S.C. § 824a-3 provide in pertinent part:

> (a) Cogeneration and small power production rules
>
> Not later than 1 year after November 9, 1978, the Commission [FERC] shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, which rules require electric utilities to offer to -
>
> (1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and
>
> (2) purchase electric energy from such facilities . . .
>
> (b) Rates for purchases by electric utilities
>
> The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase -
>
> (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
>
> (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.
>
> No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

[7] 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.

[8] *See, e.g., Armco Advanced Materials Corp. v. Pennsylvania Pub. Util. Comm'n,* 535 Pa. 108, 634 A.2d 207, 209 (Pa. 1993).

incremental cost requirement.[9] While the applicable statutes and rules are matters of federal law, PURPA grants state utility regulators the responsibility of determining a utility's avoided costs as well as terms and conditions of PURPA contracts.[10] In response, this Commission initiated and developed rules implementing the federal and state requirements.

Q. Under PURPA, are utilities or their customers intended to subsidize QFs in order to achieve PURPA's policy goals?

A. Absolutely not. 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:

> [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.[11]

The Commission has repeatedly acknowledged the importance of ratepayer

---

[9] *See American Paper Inst. v. American Elec. Power Serv.,* 461 U.S. 402, 406 (1982) (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 § 210(d) of PURPA"). FERC's definitions of terms used in implementing PURPA are found at 18 C.F.R. § 292.101. The term "avoided costs" is defined 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).

[10] *Idaho Power Co. v. Idaho Pub. Util. Comm'n.*, 316 P.3d 1278, 1280 (2013) ("*Idaho Power Co.*") (citing *FERC v. Mississippi,* 456 U.S. 742, 751 (1982)).

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

indifference when setting PURPA policies.[12] Indeed, the Commission has identified ratepayer indifference as its "primary aim."[13]

FERC has likewise affirmed the need to ensure customer 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."[14] Under PURPA, then, customers must remain indifferent or unaffected by QF contracts.

Further, this Commission has recognized that the term of a PURPA contract and the rates to be paid under that contract are interrelated. Indeed, both avoided costs *and* other terms and conditions of PURPA contracts affect whether retail customers remain indifferent to the purchase of QF power. The modification requested by the Company in this application is necessary to maintain the ratepayer indifference standard and protect customers from unnecessary fixed-price risk.

---

[12] *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.")

[13] 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.")

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

PacifiCorp has Experienced a Significant Increase in Schedule 37 PPA Requests.

Q. **Has PacifiCorp executed a significant number of PURPA contracts in recent years in response to its federal obligation?**

A. Yes. PacifiCorp currently manages 145 PURPA contracts totaling 1,991 MW of nameplate capacity across its six-state system. Of this total, 101 projects totaling 1,814 MW (91 percent of the total PURPA project capacity under contract) have online dates of 2007 or later, demonstrating that significant activity has occurred in the last seven to eight years. Of this total, 51 projects totaling 1,145 MW (58 percent of the total PURPA project capacity under contract) have online dates of 2014 or later, further demonstrating the exponential increase in PURPA contract requests and resulting contracts that have occurred in the last two years.

As previously mentioned, the Company has 338 MW of PURPA projects under contract in Oregon alone. There have been 49 new Schedule 37 QF contracts totaling 278 MW executed since the Commission first ordered 15-year fixed price terms in 2005 (Order No. 05-584). Twelve of those 49 contracts, totaling 104 MW, have been executed since April 2014. Forty two of the 49 executed contracts have a 15-year fixed-price term.

This dramatic increase in PURPA contract executions and pricing requests in Oregon and system-wide in the last year could not have been anticipated when the Commission last reviewed the appropriate term of fixed-price contracts, and demonstrates that additional review of the contract term for Oregon QFs is warranted at this time.

Q. Please describe the current magnitude of PPA and pricing requests for PURPA contracts in Oregon and across PacifiCorp's system.

A. As of May 1, 2015, the Company has 40 QF project requests totaling 587 MW of nameplate capacity in Oregon. System-wide, the Company currently has requests from 115 projects totaling 4,017 MW of nameplate capacity. Table 2 shows the number of project requests and the total QF project capacity by resource type for each of PacifiCorp's six states:

Table 2

State	Wind		Solar		Other		Total	
	Projects	MW	Projects	MW	Projects	MW	Projects	MW
California								
Idaho	1	20	20	511	2	5	23	536
Oregon			39	583	1	4	40	587
Utah	5	354	37	1,958			42	2,312
Washington								
Wyoming	9	649					9	649
TOTAL	15	1,023	97	2,985	3	9	115	4,017

Exhibit PAC/101 provides detailed information on the PPA and pricing requests, including each project location (state), size (nameplate capacity), type (i.e. solar, wind), and proposed online date. Project names have been withheld to maintain confidentiality of customer information.

Q. How does the number of executed Oregon PURPA contracts and proposed Oregon PURPA contracts compare to PacifiCorp's typical Oregon load requirements?

A. PacifiCorp has 338 MW of executed PURPA contracts in Oregon and 587 MW of proposed PURPA contracts in Oregon, together totaling 925 MW of nameplate capacity. Using 2014 as an example, PacifiCorp's maximum total retail load in Oregon was 2,598 MW, its minimum load was 1,027 MW, and its average load was

1,661 MW. The 925 MW of executed and proposed PURPA contracts in Oregon at their nameplate capacity could supply 56 percent of the Company's average Oregon retail load and 90 percent of the Company's minimum Oregon retail load.

Q. How does the number of executed PURPA contracts and proposed PURPA contracts across PacifiCorp's system compare to PacifiCorp's typical six-state system load requirements?

A. PacifiCorp has 1,991 MW of executed PURPA contracts and 4,017 MW of proposed PURPA contracts, together totaling 6,007 MW of nameplate capacity. Using 2014 as an example, PacifiCorp's maximum total retail load across its six-state system was 10,314 MW, its minimum load was 4,967 MW, and its average load was 6,844 MW. The 6,007 MW of executed and proposed PURPA contracts at their nameplate capacity would be enough to supply 88 percent of PacifiCorp's average retail load and 121 percent of PacifiCorp's minimum retail load.

THE COMPANY'S OREGON PURPA CONTRACTS WILL RESULT IN HIGHER CUSTOMER RATES, IN CONFLICT WITH THE RATEPAYER INDIFFERENCE STANDARD

Q. What impact should PURPA contracts have on customer rates?

A. PURPA contracts should have no impact on customer rates. As this Commission and state regulators across the country have stated time and time again, retail customers should be indifferent to the purchase of QF power. As FERC has noted, 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."[15]

In short, customers must remain indifferent or unaffected by PURPA contracts. The modification to the maximum fixed-price contract term requested by the Company in this application is necessary to maintain this indifference standard.

Q. Why is it critical to make the needed modification to QF contract term quickly once it has been identified?

A. As mentioned earlier in my testimony, PacifiCorp currently has 338 MW of executed PURPA contracts in Oregon and 587 MW of proposed PURPA contracts in Oregon, together totaling 925 MW of nameplate capacity. The Company has 145 existing (executed) PURPA contracts totaling 1,991 MW of nameplate capacity across its six-state system.

Under PacifiCorp's multi-state jurisdictional cost allocation model, PURPA contracts are considered system resources and are allocated to each of the six states based on the System Generation allocation factor. Oregon's allocated share is typically around twenty-five percent. The expected system-wide costs (payments to QFs) over the next ten years from PacifiCorp's total executed PURPA contracts is $2.9 billion. In 2015 alone, the projected payment to QFs is $170.5 million, with Oregon's allocated share at $42.6 million.[16]

If QF projects are priced higher than the market alternative by just ten percent, the impact to Oregon customers would be $4.3 million in 2015 alone,

[15] *Southern Cal. Edison Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269 at p. 62,080 (1995).
[16] Assuming an Oregon allocation factor of 25 percent.

which is in direct conflict with PURPA's ratepayer indifference standard. That 10 percent impact would grow to a total of $72.5 million in additional costs to Oregon customers over the ten-year period starting in 2015.

With outstanding requests for new QF PPAs across the Company's system totaling 4,017 MW, or more than double (in MW) the size of the $2.9 billion worth of current PURPA contracts to which the Company is already obligated, it is imperative that Oregon customers be protected from the long-term, fixed-price risk that comes with a 15-year or longer contract term for QFs. Failure to implement the modification to contract term proposed by the Company in this case may result in significant irreversible harm to customers.

THE COMMISSION SHOULD REDUCE THE FIXED-PRICE CONTRACT TERM FROM 15-YEARS TO THREE YEARS.

Q. Does the Commission have discretion to determine the appropriate contract term under PURPA?

A. Yes. Although PURPA's federal mandate requires utilities to purchase QF power, PURPA's scheme of cooperative federalism gives state regulatory agencies the authority to protect 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.[17] 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]

[17] *Idaho Power Co.,* 316 P.3d at 1280; *Exelon Wind I, LLC*, 766 F.3d 380 (5th Cir. 2014).

regulations."[18]

A critical element of the utility's must-purchase requirement under PURPA is the contract term. This is because FERC generally requires a utility to lock in forecasted avoided cost rates for the entire contract term.[19]

Q. Has the Commission ever reduced the contract term for QFs in Oregon?

A. Yes. In 1996, as competitive markets began to emerge, the Commission limited the terms of QF contracts to five years. On October 30, 1996, PGE 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.

The Commission Staff in its memo to the Commission noted "[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.[20] The Commission agreed with Staff and adopted PGE's filing at their December 1996 public meeting, thereby establishing a five-year contract term 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 limits the possible divergence of standard contract rates from actual avoided

---

[18] *Cal. Pub. Util. Comm'n,* 133 FERC ¶ 61,059 at P 24 (2010).
[19] *See Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA*, 45 Fed. Reg. 12214, 12224 (1980).
[20] Staff Report for December 17, 1996 Public Meeting, at 4.

costs. In Order No. 05-584, the Commission increased the fixed price contract term to 15-years, citing “We 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.”[21]

The Company is now faced with the same concerns as in 1996 where the position taken by Staff and the Commission’s decision was consistent with the request the Company is now making. In the current market environment, long-term QF power purchase agreements pose significant price risk and harm to its customers because these QF contracts are longer than the typical contracting and hedging horizons for energy contracts available to the utility industry today.

Q. Have other state commissions in the Company’s service area recently addressed this issue?

A. Yes. The Idaho Public Utilities Commission (Idaho Commission) has recently addressed the need to reduce QF contract terms to protect ratepayer neutrality. Initially, the Idaho Commission set PURPA contract terms at 35 years to match the amortization period allowed for similar utility owned facilities, making financing easier, thus encouraging QF development.[22] Later, the Idaho Commission began to recognize concerns related to the risk and uncertainty inherent in long range forecasting and shortened the contract length to 20 years.[23]

The Idaho Commission shortened the contract term to only five years in

[21] In the Matter of Public Utility Commission Of Oregon Staff’s Investigation Relating to Electric Utility Purchases from Qualifying Facilities, Docket UM 1129, Order 05-584 p. 19.
[22] *See, e.g.* Case No. GNR-E-02-1, Order No. 29029 (Ida. PUC May 21, 2002) at 2 (describing the origin of PURPA regulation in Idaho).
[23] Case No. U-1500-170, Order No. 21630 (Ida. PUC Dec. 2, 1987).

1996 and 1997 (first for QFs of 1 MW and larger, then for QFs under the 1 MW cap) in order to align the QF contract time frame with the utilities' acquisition strategies.[24] The Idaho Commission noted in that case that a 20-year contract obligation did not reflect the manner in which the utilities were acquiring power to meet new load, which at the time was through contracts with terms of five years or less, and that "it would be nothing more than an artificial shelter to the QF industry to provide those projects with contract terms not otherwise available in the free market."[25] In 2002, the Idaho Commission raised the contract length back to 20 years, expressing concerns about a scarcity of QF contracts signed since the prior change.[26]

Since then, concerns regarding the viability of QFs are no longer at the forefront. First in 2011, the Idaho Commission issued Order No. 32262 on June 8, 2011 maintaining a 100kW cap on wind and solar QF projects eligible for standard avoided cost prices.[27] Then, in 2015, the key concerns about PURPA contracts have resurfaced and are similar to those that were present at the time of the Idaho Commission's 1996 and 1997 orders reducing the term to five years, *i.e.*, the current concerns stem from the magnitude of QF power flowing onto utilities' systems without any finding of utility need and resulting concerns about price risk, reliability, and customer indifference. As a result, the Idaho Commission has

[24] Case No. GNR-E-02-1, Order No. 29029 (Ida. PUC May 21, 2002) (describing the history of changes in approved term of QF contracts in Idaho).
[25] Case No. IPC-E-95-9, Order No. 26576 (Ida. PUC Sept. 4, 1996) p. 13.
[26] *See* Case No. GNR-E-02-1, Order No. 29029 (Ida. PUC May 21, 2002) p. 7 (stating that it "could not ignore the fact that since reducing the eligibility threshold to 1 MW and contract term to 5 years, there has been only one PURPA contract signed in Idaho.").
[27] Case No. GNR-E-11-01, Order No. 32262.

recently reduced the term of PURPA contracts for the Company, Idaho Power and Avista to five years for solar and wind QF projects larger than 100 KW pending completion of a docket considering a permanent reduction.[28]

Q. Can a 15-year fixed-price contract term be considered a "subsidy" to a QF?

A. Yes. Given the typical contracting and hedging horizons for energy contracts in the utility industry, which are commonly limited to less than 36 months, it is extremely rare for a utility to voluntarily enter into a 15-year fixed-price energy contract without a specified energy resource need due to concerns about price risk, market liquidity, and other risk considerations. Under the Commission's current PURPA policies, however, any QF can obtain a 15-year, fixed-price energy contract at the Company's projected avoided cost, without any economic considerations or price adjustment to account for the risk to utility customers from this unusually long-term transaction, or to the QF to account for the price certainty the QF enjoys from such a contract.

As noted above, this Commission has recognized establishing rules for QFs that the avoided cost rates are not the only term of a power purchase contract with a QF that can affect the required ratepayer neutrality.[29] Contract length is also a PURPA contract term, and this term carries its own economic value. To grant QFs access to long-term price certainty with no adjustment to the price to account for that certainty is granting QFs something no other market participant enjoys. For

[28] Case No. IPC-E-15-01, Order No. 33222 (Ida. PUC Feb. 6, 2015) (Idaho Power), Order No. 33250 (Ida. PUC Mar. 13, 2015) (Rocky Mountain Power and Avista), and Order No. 33253 (Ida. PUC Mar. 18, 2015) (clarifying that the interim reduction applies to QF projects that exceed the published rate eligibility cap (up to 100 KW for solar and wind and up to 10 average megawatts (aMW) for QFs of all other resource types)).
[29] Order No. 81-319 at 3 (recognizing that non-rate terms "ultimately affect the total cost of purchasing power from the [QFs].").

this reason, I would view a guaranteed, fixed-price, 15-year contract at avoided cost to be a QF subsidy.

Q. Is there evidence that supports the Company's requested modifications?

A. Yes. My testimony presents substantial and compelling evidence demonstrating why the Company's requested modification is necessary in order to maintain the ratepayer indifference standard.

15-YEAR PURPA CONTRACTS ARE INCONSISTENT WITH CURRENT HEDGING PRACTICES AND RISK POLICIES AND REQUIRE CUSTOMERS TO BEAR AN INAPPROPRIATE AND UNNECESSARY LEVEL OF PRICE RISK

Q. When the Company considers purchasing power from a third party, does the Company first review the proposed purchase from a resource need and a risk-management perspective?

A. Yes. The Commission expects the Company to serve its customers with least-cost, least-risk resources. For that reason, the Company has integrated resource planning processes and risk-management policies it applies to evaluate any proposed energy contracts, to ensure the contracts are reasonable and prudent.

Q. Does the Company apply its integrated resource planning process and internal risk management policies to PURPA contracts?

A. No, not in the same way as it does for non-PURPA contracts. The Company cannot refuse to execute PURPA contracts based on the price or the contract term, or based on other transaction parameters that it would normally not accept for non-PURPA contracts. Under PURPA, the Company must purchase QF energy and capacity regardless of whether the Company needs the power, on terms and conditions established by its state commissions.

Q. How does the Company manage PURPA contract risk?

A. While the Company has some limited ability to negotiate PURPA contract terms and conditions for its non-standard or Schedule 38 contracts, the Company has no ability to negotiate PURPA contract terms under Oregon Schedule 37 which utilizes standard contract templates that are approved by the Commission. While the Company uses its non-QF resources to integrate QF power into its system as efficiently and reliably as possible, PURPA requires the Company to rely primarily on its state regulatory commissions to regulate customer exposure to risk through the establishment of terms and conditions of its PURPA contracts.

Q. How does the Company manage non-QF-related trading risk?

A. The Company's trading policies and procedures are outlined in PacifiCorp's Risk Management Policy, which sets forth how the Company identifies, assesses, monitors, reports, manages, and mitigates each of the various types of commercial risk associated with energy trading. Energy commodities include, but are not limited to, physical and financial transactions of electricity and natural gas, #2 fuel oil, unleaded gasoline, renewable energy credits, SO_2 emission allowances, and greenhouse gas allowances.

PacifiCorp's Energy Supply Management (ESM) organization (formerly known as the Commercial and Trading, or C&T) manages the energy commodity position and utilizes PacifiCorp's assets and liabilities (loads, generating resources, contractual rights, and obligations) to: (i) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (ii) reduce volatility of net power costs for PacifiCorp's customers.

PacifiCorp's commodity risks are managed through a control and limit structure that defines the maximum levels of market risk and credit capacity permissible for the Company to engage in trading and risk management activities. Compliance with this policy is mandatory.

Q. Please explain the circumstances that led to changes in PacifiCorp's Risk Management Policy, reducing the contract length of PacifiCorp's electricity and natural gas hedges.

A. As a result of the sharp decline in natural gas prices over the last several years, losses resulting from the Company's natural gas hedging temporarily exceeded the market-purchase alternative. In the 2012 TAM, this led to litigation over the prudence of these losses and the reasonableness of the Company's underlying hedging policies. In the Commission's final order in the 2012 TAM, the Commission rejected a challenge to the prudence of the Company's natural gas hedges and approved a stipulation among the Company, Commission Staff, Noble Americas Energy Solutions, LLC, and the Citizens' Utility Board of Oregon (CUB).[30] In that Stipulation, the Company agreed to a collaborative process on natural gas hedging in Oregon, similar to processes underway in other PacifiCorp jurisdictions.[31]

---

[30] *In the Matter of PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism*, Docket UE 227, Order No. 11-435 (Nov. 4, 2011).

[31] Section 13 of the Stipulation in the 2012 TAM states:

> Hedging Policy. PacifiCorp agrees to enter into a series of workshops with interested parties to review PacifiCorp's going-forward hedging policy in detail and seek input from the interested parties on how the policy is implemented and whether the policy should be revised to better reflect customer risk tolerances and preferences. While all Parties agree that this is not, and will not be, stated to be a pre-approval process in any future prudence review, the Company agrees to implement appropriate policy changes on a going-forward basis that result from agreement in the collaborative process.

Q. Did the Commission endorse this provision of the stipulation in its final order in the 2012 TAM?

A. Yes. The Commission's order included the following statement on the goals of the collaborative process on natural gas hedging:

> We encourage Pacific Power to work with Staff and stakeholders in workshops, as the company has committed to do, to address any stakeholder concerns about the company's present and future hedging strategies. The company states that it welcomes *ex ante* direction from the Commission on the company's risk management policy and hedging program, which we believe should start with stakeholder involvement.[32]

Q. Consistent with the final order in the 2012 TAM, did the Commission convene a natural gas hedging workshop in Oregon in 2012?

A. Yes. The Commission convened a hedging collaborative workshop on March 19, 2012, with all three commissioners present. Representatives from Oregon's electric investor-owned utilities, Commission Staff and stakeholder groups all attended. At the workshop, PacifiCorp explained how its natural gas hedging policy had evolved in response to customer feedback in Oregon and other jurisdictions. Most notably for purposes of this testimony, the Company announced its intention to reduce its standard hedging time horizon from 48 months to 36 months. In the 2012 TAM, both the Industrial Customers of Northwest Utilities (ICNU) and CUB had argued in favor of a 36-month hedging time horizon.

Q. Since 2012, has PacifiCorp adhered to a maximum 36-month contract length for natural gas and electric hedges?

A. Yes. PacifiCorp actively manages electricity and natural gas short- and

[32] *Id.* at 12.

long-positions that are 36 months out and nearer, meaning up to three years from today. Traders have risk limits that they must maintain in order to limit customer price exposure to the Company's open position over this three year time horizon. This trading practice 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.

Q. Do PacifiCorp traders actively manage or hedge positions beyond the prompt 36 months?

A. No. The Company's practice since it completed the hedging collaborative workshops in 2012 has been to limit hedges to 36 months or less unless stakeholders express interest for longer term hedges. There has been no expressed interest for electricity hedges beyond 36 months since that time. The Company's risk management metrics are limited to 36 months.

Q. Why are these risk management and hedging policies and requirements applicable to the Company's PURPA contracts?

A. The Company is obligated by law to purchase electricity from QFs at prices and on terms set forth by its state commissions. In this sense, the Company's primary vehicle for risk management review of PURPA contracts are the policy decisions made by each state commission.

Q. Can you provide an example showing the inconsistency between the Company's hedging policies and its PURPA contracting requirements?

A. Yes. 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. But the Company is mandated to enter into 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 not consistent with the hedging policy put in place as a direct result of input from stakeholders and is harmful to customers.

Q. What process would PacifiCorp undertake when contemplating a non-PURPA transaction that exceeds the typical 36-month time horizon?

A. Non-PURPA transactions that exceed 36 months in effective transaction period require extensive analysis and progressively higher level of management review. The analysis includes a review of the need for the transaction, a comparison of the contemplated transaction to other available transactions that meet the same need, a thorough economic analysis to demonstrate that the transaction is the least-cost, least-risk way to meet the identified need, and an extensive review of credit terms and contract terms. Typically the level of detail, documentation, and review increases commensurate with the size and duration of the transaction, which also increases the level of management approval that is required.

The Company primarily enters into long-term transactions (those that exceed 36 months) only when there is a clearly identified long-term resource need in its IRP. Long-term resource needs are typically identified in the IRP only after lower-cost, lower-risk short-term resource opportunities are exhausted such that a long-term resource is required to meet customer load requirements.

Q. When the Company enters into a long-term transaction as a result of the IRP action plan, what additional steps are taken to protect customers?

A. The Company typically utilizes a rigorous RFP process to acquire any long-term transaction or resource need directed by the IRP action plan. This process often involves extensive input from regulators in the drafting and management of the RFP. In fact, the process often includes independent evaluator[33] review of the process and ultimate results.

In Oregon, if the resource or transaction involves a generating resource that produces 100 MW or more or has a term of five years or more that will produce 100 MW or more, the Company is required to go through this process.[34] This robust process ensures the Company acquires only what is needed and results in a long-term transaction at the lowest cost possible. In addition to the extensive RFP process, any long-term transaction goes through the analysis and review process I described in conjunction with the PacifiCorp Risk Management Policy.

Q. Do these same steps occur prior to entering into a PURPA contract?

A. No. PURPA contracts do not go through the same extensive IRP process to determine if they are needed or if they are the least-cost, least-risk option. PURPA contracts do not go through the same competitive bid RFP process including

[33] An independent evaluator is a third party who is appointed by the Company's regulators to oversee the RFP process to ensure fairness throughout the process and to ensure the bids are accurately evaluated. *See* Docket No. UM 1182, Order No. 06-446 at 5 (Aug. 10, 2006).

[34] *Id.* at 2 (Aug. 10, 2006) ("A utility must issue an RFP for all Major Resource acquisitions identified in its last acknowledged Integrated Resource Plan (IRP). Major Resources are resources with durations greater than 5 years and quantities greater than 100 MW).

oversight by an independent evaluator to ensure they are lowest cost. PURPA contract executions are not limited to the size of the resource need in the IRP action plan. And, PURPA contracts do not receive the same upper management review and analysis because upper management does not have the discretion to refuse the mandatory purchase obligation and the 15-year fixed price contract term established by the Commission. The Company is asking the Commission to use its discretion to implement the change necessary to protect customers.

Q. Why is such a rigorous review process necessary when entering into long-term transactions, and why does the Company generally limit trading and hedging activities to 36 months?

A. The primary reason is long-term fixed price energy contracts carry significant price risk. The market becomes more and more uncertain as you move further into the future, and it is difficult to forecast with reasonable certainty what prices will be far out into the future. Long-term fixed-price transactions often move in or out of the money over time as the forward price curve changes. For these reasons, unless the Company has a demonstrated need for resources in its IRP, it does not pursue long-term transactions.

Q. Is there additional market and industry evidence that supports the Company's 36-month trading and hedging horizon?

A. Yes. In the unregulated wholesale energy marketplace, very few transactions occur beyond a six-year time horizon and the highest volume of transactions occur within one year. When the Company has entered into long-term, non-QF transactions in the past several years, it is the result of a specific need for a resource identified in the IRP and the contracts are typically backed by an identified firm resource (*i.e.*, a utility has load growth, generating unit retirements, or expiring contracts and needs a resource, so it contracts to buy the output from a certain generator). Most of these long-term transactions occur through a rigorous, transparent, and competitive RFP processes.

Further evidence of the industry preference for shorter-term fixed-price contracts is found in the practices of most of PacifiCorp's combined heat and power (CHP) QFs.[35] CHP QFs generally do not need long-term contracts for financing purposes (most use balance sheet financing), so these types of QFs evaluate a desired contract term from a risk management perspective. Like most utilities, CHP QFs typically elect short-term contracts with PacifiCorp even when long-term PPAs might be available. In fact, most elect annual contracts that are renewed each year at the then-current avoided costs. These CHP QF customers have told PacifiCorp that they are not energy traders and therefore prefer to take the spot or near-term avoided cost price in order to eliminate the price risk that comes from long-term, fixed-price contracts.

Q. Can you provide an example of the price risk associated with a long-term fixed price contract?

A. Yes. The electricity and natural gas markets have fallen dramatically in the past year as oil prices have also declined. On August 1, 2014, a ten-year fixed-price contract for a seven-day by 24-hour electricity product at the Mid-Columbia

[35] In Oregon, the CHP QFs are generally in the forest products industry, using steam for drying and generating a nominal amount of power.

(Mid-C) wholesale power market trading hub was priced at $45.87 per MWh. On May 1, 2015, just twelve months later, that same ten-year contract was priced at $35.27 per MWh. The ten-year electricity market declined 23 percent in just twelve months. Hypothetically, had the Company purchased 100 MW of this ten-year fixed-price electricity on August 1, 2014, at $45.87 per MWh, just twelve months later the Company would have a nominal mark-to-market loss of $93.0 million on the contract.

By comparison to this 100 MW ten-year example, the Company currently has 587 MW of proposed PURPA contracts in Oregon seeking 15-year fixed-price contracts. Not only are the volume and price difference greater but the length of the contract is longer than the example provided. The price risk associated with this large number of proposed long-term, fixed-price contracts is substantial and should not be borne by customers.

Q. How do you respond to the argument that market prices are currently "low" and therefore the Company should lock in as much energy as possible?

A. Locking in a price because you are speculating that the price is "low" is not risk management or hedging—it is speculative trading. The Company and its customers are not speculators. The Company's customers expect the Company to provide safe and reliable energy while employing the "least-cost, least-risk" principle. Taking a long-term, fixed-price position in a commodity does not follow this principle.

Q. Has this long-term price risk been evidenced in the Company's existing PURPA contracts?

A. Yes. The Company currently has 145 PURPA contracts totaling 1,991 MW of nameplate capacity across its six-state system. Oregon's allocated share of these contract costs averages approximately 25 percent. Over the next ten years, the Company is under contract to purchase 44.6 million MWh under its PURPA contract obligations at an average price of $64.13 per MWh. The average forward price curve for Mid-C for this same ten years is $35.27 per MWh,[36] or a difference of $28.86 per MWh. Thus, PacifiCorp's customers would be expected to pay over $1.2 billion more than current market prices over the next ten years on a system-wide basis, and Oregon customers would be expected to pay over $320 million more.

Q. Under current policies and QF pricing methods, can the Company protect customers from long-term price risk when entering into PURPA contracts?

A. No. Unlike a need based long-term transaction, a mandatory purchase under a PURPA long-term fixed price contract must be executed regardless of need. Consequently, these long-term contracts unnecessarily expose customers to price risk that is not reflected in the contract price.

Long-Term Resource Planning: PacifiCorp's IRP Process and Current Resource Needs

Q. How does the Company determine its long-term resource needs?

A. The Company's long-term planning and resource decisions are thoroughly

[36] Based on a May 1, 2015 forward price curve for a 7x24 (flat) electricity product.

evaluated through the Company's IRP process. PacifiCorp's IRP is developed with participation from public stakeholders, including regulatory staff, advocacy groups, and other interested parties. The planning process entails: (1) developing an assessment of resource need via a load and resource balance, reflecting current load growth forecasts and existing resources and contracts over a 20-year planning horizon; (2) producing a range of different resource portfolios that could be used to meet the projected resource need; and (3) evaluating the comparative cost and risks of each resource portfolio, taking into consideration a wide range of planning uncertainties, in order to identify the least-cost and least-risk preferred portfolio. Once a preferred portfolio is selected, an action plan is developed that identifies the specific resource actions the Company will take over the next two to four years to implement its resource plan.

Q. How does the IRP influence the types of long-term transactions entered into by the Company?

A. The Company would not plan to enter into long-term transactions unless a long-term resource need is identified in the IRP preferred portfolio. As noted above, long-term resource needs are typically identified in the IRP only after lower-cost, lower-risk short-term resource opportunities are exhausted such that a long-term resource is required to meet customer load requirements. If the IRP identifies the need for a long-term resource in the near-term, an IRP action item would specify the Company's plans to acquire the resource, which might include issuance of an RFP.

Q. What long-term transactions have been included in recent and current IRP action plans?

A. The 2013 IRP, which until the recent filing of the 2015 IRP is acknowledged serves as the reference for avoided costs in Oregon, included a combined cycle combustion turbine (CCCT) gas plant in 2024. 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, filed with the Commission in March 2014, pushed the CCCT out to 2027. Again, due to the timing of this identified need, the Company has not developed 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. As in the 2013 IRP and the 2013 IRP Update, the 2015 IRP draft action plan does not include any action items to procure this long-term resource.

Q. What conclusion can you draw from the 2015 IRP preferred portfolio and associated draft action plan?

A. The Company does not have a need for a new long-term resource until 2028, and due to the timing of this need, the Company will not have any action items to procure a new long-term resource in the next two to four years.

Q. How is the Company's proposal to limit QF contract terms to three years in length aligned with the IRP planning process?

A. The full IRP is published every other year, with an update published in the off years. As described earlier in my testimony, the IRP process includes a rigorous review of the Company's resource needs by evaluating its load and resource balance and establishing a least-cost, least-risk resource plan through comprehensive and rigorous modeling of numerous resource alternatives. The planning environment is constantly changing. This is evident in the changes in the Company's load and resource balance, state and federal environmental policies, wholesale power and natural gas prices, market products, market rules and contracting practices, and cost and performance of new generating technologies, to name a few.

While the Company's planning process is robust and designed to reasonably capture a wide range of uncertainties, the magnitude of the various planning uncertainties grows as you get further out into the IRP 20-year planning horizon. It is for this very reason that IRP action items focus on the front two to four years of the planning period and that the IRP planning process is repeated every two years with updates in the off years. Even within these biannual planning cycles, material changes in Company's resource needs have been observed from one IRP to the next. The Company's proposal to limit QF contract terms to three years in length is more aligned with the two-year IRP planning cycle, and the associated two- to four-year action plan period. Aligning a QF contract term limit to the IRP planning cycle will ensure avoided cost pricing remains consistent with the most up-to-date information regarding the Company's resource needs and limit long-term price risk.

ELIGIBILITY CAP FOR OREGON SCHEDULE 37

Q. Should the Commission change the 10 MW cap for the Schedule 37 contract?

A. Yes. 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 QF projects. My testimony primarily focuses on solar because of the significant backlog of solar QF requests.

A 10 MW solar project is not a small project, requiring approximately 60 acres of land. It requires significant capital expense typically ranging between $18 million and $24 million. It requires detailed interconnection studies consistent with Oregon rules and the transmission provider's transmission tariff. And frankly, the effort to develop a 10 MW QF project is no less than a 20 MW or even an 80 MW solar project except for possibly the transmission interconnection voltage. Therefore a 10 MW cap is really not an effective measure to define a small project from a development perspective.

Reducing the eligibility cap will do several things: (1) 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; (2) continue to maintain the PURPA objective of minimizing transaction costs for small QFs; (3) ensure that avoided cost rates reflect the project specific operating characteristics as compared to the proxy resource, whether standard or renewable; and (4) 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.

Q. Do Schedule 37 prices paid to wind and solar projects result in accurate pricing?

No. As detailed above, avoided costs must comply with PURPA's overarching ratepayer indifference under which prices paid to a QF "may be no higher than the cost the utility would have incurred for the power had it not purchased QF energy and/or capacity…"[37] FERC's implementing regulations make this point abundantly clear: "[n]othing in this subpart requires any electric utility to pay more than the avoided costs for purchases."[38] The customer indifference standard has been affirmed by the Supreme Court and repeatedly acknowledged by this Commission.[39]

The current 10 MW eligibility threshold for standard rates ensures that PacifiCorp's customers are *not* indifferent to QF purchases. The Commission recognizes that standard rates may result in payments to QFs that exceed a utility's actual avoided costs because avoided costs do not reflect a particular QF's unique operational characteristics.[40] In fact, the Commission has expressly acknowledged that "the application of our current [standard rate] methodology may result in the utility and its customers offering prices in excess of actual avoided costs."[41]

As the Commission has recognized, standard rates do not reflect the true price to customers of QF output. Few, if any, of the QF resources eligible for standard prices produce energy that provides equivalent value to the proxy resource energy. Most QF resources receiving standard prices avoided cost prices are, to some degree, receiving incremental value based on the difference between the

---

[37] *So. Cal. Ed.*, 71 F.E.R.C. ¶ 62,079.
[38] 18 C.F.R. § 292.304(2).
[39] *Am. Paper Inst.*, 461 U.S. at 413 ("avoided cost [are] the *maximum* rate that [FERC] may prescribe." *See also, e.g.,* Order No. 14-058 at 3 (Oregon's PURPA rules must "[ensure] that utilities pay no more than avoided costs.").
[40] *See* 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."); Order No. 14-058.
[41] Order No. 14-058 at 7.

operating characteristics of the QF resource and the proxy plant, and therefore do not always reflect the true avoided cost to the utility.

This divergence from applying the project specific characteristics to calculate standard pricing does not account for system impact costs of the individual QF, and will lead to the Company's customers carrying the burden of a higher-cost QF resource. The disconnect between standard pricing and actual avoided costs (and the associated customer impact) is magnified as the size of a QF project increases.

Q. Would lowering the eligibility threshold to 100 kW for wind and solar projects result in more accurate pricing?

A. Yes. 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 QF projects. In fact, FERC's and the Commission's regulations make clear that project-specific factors must be taken into consideration when avoided cost prices are set.[42] This will result in more accurate avoided cost pricing by allowing avoided costs to reflect a QF's unique characteristics. 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.

Q. Has the 10 MW cap encouraged the development of small QF projects?

A. No. The Commission confirmed the 10 MW cap in February 2014 in Order No. 14-058. The Commission stated that if the eligibility cap was lowered, "[s]mall

[42] 18 C.F.R. § 292.304(e) (listing specific factors that "shall, to the extent practicable, be taken into consideration" when setting avoided cost prices); OAR 860-029-0040(5) (same).

QFs under 10 MW may lack the resources to negotiate complex modeling and inputs with a utility."[43] The Commission's conclusion misapprehends the nature of current QF development in Oregon, where the vast majority of development is being driven by large, sophisticated, out-of-state developers. In fact, the majority of new PPA requests are coming from QFs at or near the 10 MW cap, rather than smaller projects.

Q. Please describe the current development of Schedule 37 solar projects in Oregon.

A. Prior to mid-2013, the PPA requests for solar projects eligible for Schedule 37 was limited and generally from developers in Oregon and the Pacific Northwest. Beginning in the second half of 2013, the Company began receiving inquiries from out-of-state developers on Schedule 37 requirements. In 2014 between the months of March and August, the Company received 33 requests totaling 272 MW from six developers. Three developers were from the Northwest and three were from the east coast and Canada.

The developers from outside the Northwest submitted 25 PPA requests totaling 216 MW including one developer, Solexus Development of Missouri, that submitted seventeen Schedule 37 contract requests over a four-month period in an attempt to secure the pre-August 20, 2014 avoided cost prices. Exhibit PAC/102 contains the Schedule 37 solar PPA request activity since January 2014. Many of these developers found they could prospect and secure land purchase or lease options for parcels across Oregon and submit multiple Schedule 37 PPA requests at

[43] Order No. 14-058 at 7.

one time for projects while having minimal in-state involvement with the state, county, or local community. In fact, some developers simply downloaded the Company's draft Schedule 37 PPA from the Pacific Power website, executed the PPA, and submitted it without any prior contact with the Company.

Q. **Does the Company expect the Schedule 37 PPA requests to slow down in 2015?**

A. No. From mid-April 2015 through mid-May 2015, the Company has received 13 Schedule 37 PPA requests totaling 119 MW from three developers, two of which are national and international developers. Of the thirteen projects, ten are being proposed at the 10 MW maximum. All of the PPA requests are seeking to execute their contracts on an accelerated basis to receive the current Schedule 37 avoided cost prices before the Company's filing for updated prices made on May 1, 2015, become effective.

Q. **What do you see as the key drivers on high influx of Schedule 37 PPA requests?**

A. There are four key drivers. First, the federal investment tax credit will change on January 1, 2017, when it will drop from 30 percent to 10 percent.

Second, project costs have been falling. Market data from various solar trade organizations are showing total installation costs for utility scale systems have fallen below the $2.00 per watt (direct current), which is below the cost of just the panels in 2011. While panel prices have remained constant for the past couple of years, balance-of-system costs have continued to drop by 10 percent or more.

Third, developers are timing requests for PPAs with scheduled avoided cost price updates, the most recent of which was filed by the Company on May 1, 2015 seeking an effective date of June 1, 2015. When developers see a downward price change is pending, QF requests spike.

The fourth driver is the fact that developers appear to be siting projects in Oregon, rather than Washington or Idaho, due to favorable contracting policies. The Company's standard avoided cost prices in Washington are available to QFs up to 2 MW. And the Idaho Commission recently lowered the eligibility threshold for standard avoided cost prices for wind and solar QFs to 100 kW.[44] The dissymmetry in eligibility thresholds has encouraged developers to site projects in Oregon, rather than in Washington and Idaho.

Q. What is the impact to customers from these requests?

A. The difference in cost between the QF resource and the proxy plant has become more significant since the eligibility cap was raised from 1 MW to 10 MW. For example, in the five years after the 10 MW eligibility cap was established in 2005, the Company experienced a high influx of wind QF PPAs eligible for Schedule 37 avoided cost prices resulting in executed PPAs totaling 115 MW. Nine of the 14 Schedule 37 wind QF PPAs are sized at 9.9 MW or 10 MW and only one wind QF project is less than 100 kW.

These large Schedule 37 wind projects are all remote, intermittent resources with low capacity factors. The cost to the Company and its customers, for integration of the resource, capacity contribution, and system transmission costs are

---

[44] Case No. IPC-E-15-01, Order No. 33222 (Ida. PUC Feb. 6, 2015) (Idaho Power), Order No. 33250 (Ida. PUC Mar. 13, 2015) (Rocky Mountain Power and Avista), and Order No. 33253 (Ida. PUC Mar. 18, 2015).

significant and yet they were not reflected in the avoided cost prices.

This same pattern is being repeated in 2014 and 2015 with solar projects but on a significantly larger scale. If all Schedule 37 solar QF requests result in executed contracts, the Company will be under contract with 584 MW of variable energy resources in which the contract price does not account for the specific project operating characteristics. The Company's proposal for reducing the eligibility cap from 10 MW to 100 kW for Schedule 37 would mitigate the ability of the larger Schedule 37 QF projects to shift those types of costs noted above to customers.

Q. Did PURPA support the concept of small QF projects receiving standard rates?

A. Yes. PURPA expressly contemplates that standard rates should apply to very small projects or those under 100 kW in order to minimize transaction costs that might otherwise keep the projects from going forward. In its order implementing the PURPA regulations, the Federal Energy Regulatory Commission (FERC) stated:

> The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rates required by this 12 paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standard tariffs be implemented for facilities 100 kW or less.[45]

In other words, the FERC acknowledged that standard rates may be higher than a project specific avoided cost rates, but approved an exception for projects less than

[45] FERC, 18 CFR Part 292, Docket RM79-55, Order No. 69.

100 kW that might otherwise be unable to afford the transaction costs of negotiating an individual rate.

Q. Does the eligibility cap serve a definitive purpose?

A. Yes. The Schedule 37 eligibility cap is a clear delineation to minimize their transaction costs for developers of small QF projects when securing a PPA with the utility. These projects are generally thought to be developed by individuals or organizations with limited resources that do not have the corporate backing, financial wherewithal, or technical skills to handle significant administrative issues or cost. These types of projects that PURPA intended should receive the benefit of standard avoided cost rates and contracts as available through Schedule 37. Another way to look at this is to examine the transaction costs related to negotiating a non-standard contract with the Company. For instance, if the QF does not introduce additional terms from the Schedule 37 PPA then negotiation of a Schedule 38 contract is no more involved than for a Schedule 37 contract. In Utah, the Schedule 37 and 38 solar contracts are the same except for specific Utah Commission orders on security. In most of our other states, the standard and non-standard are very similar. Therefore, a lower cap would result in more accurate prices that better ensure retail customer indifference, with little additional transaction cost to a developer.

As the eligibility cap has increased over time to the current 10 MW, the Company is now negotiating with 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. It is clear that the vast majority of QF developers are not the small "mom & pop" operations that PURPA was originally intended to encourage. 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 "yieldcos" for the benefit of investors and at the expense of customers.

Q. What is a "yieldco"?

A. For simplicity, I reference an article from the National Renewable Energy Laboratory (NREL) website:

> "A yieldco is a dividend growth-oriented public company, created by a parent company (e.g., SunEdison), that bundles renewable and/or conventional long-term contracted operating assets in order to generate predictable cash flows. Yieldcos allocate cash available for distribution (CAFD) each year or quarter to shareholders in the form of dividends. This investment can be attractive to shareholders because they can expect low-risk returns (or yields) that are projected to increase over time..........
>
> Renewable energy projects face some uncertainty during the development stage but tend to produce low-risk cash flows once they are operating. Yieldcos have the potential to unlock the value of these renewable assets. Yieldcos may attract new investors who may otherwise perceive unacceptable risk or lack the appropriate channels to invest capital in renewables. In exchange for the opportunity to invest in relatively low-risk assets, yieldco investors typically receive 3%–5% returns and long-term dividend growth targets of 8%–15% ……".[46]

What is important to note is the continued use of the phrases "unacceptable risk" or "low-risk" as it is applied to the benefit of project investors. Yieldcos are more and more being used in the energy industry, primarily focused on renewable energy, to

[46] https://financere.nrel.gov/finance/content/deeper-look-yieldco-structuring, last visited May 18, 2015.

protect investors against regulatory uncertainty at the expense of the utility customer, So where does the risk then reside? It is shifted to the Company's customers who are bearing the other side of the equation – paying the cost of those must take long-term fixed price QF renewable energy contracts to the benefit of the yieldco investors.

Q. What has been the impact of this new ownership model on Schedule 37?

A. It simply has created a feeding frenzy of developers across Oregon and our other states. In Oregon, the developers are using a shotgun approach to project development, seeking to secure lease or purchase options on parcels of land sufficient to hold a 10 MW solar project, running a readily available solar product program such as PVSyst to get production numbers, having a solar panel vendor generate a generic layout of panels and then submitting multiple requests for Schedule 37 contracts. Securing a lease option for rural Oregon property is very simple and straightforward. For the landowner, most have minimal income from the property and the possibility of a lease payment over time is a good income on the property. Some developers now don't even contact the Company first. They simply download a contract template from the Company website, fill it in, execute and submit it, declaring they have a legal enforceable obligation (LEO) without even talking with the Company. This was the exact situation in August 2014 when avoided prices changed and is happening again with the requested Schedule 37 price update filed May 1, 2015. We currently have 13 Schedule 37 PPA requests from 3 developers totaling 119 MW, all received after mid April 2015 and seeking the current Schedule 37 avoided cost prices before they change. One simply wrote a letter claiming a LEO and asking for a power purchase agreement for each of his projects.

Q. How would changing the eligibility cap reduce this feeding frenzy you are talking about?

A. It would do several things: (1) require wind and solar projects over 100 kW to adhere to Schedule 38 procedures which would maintain low transaction costs for the small projects in line with PURPA's directives while ensuring that projects over 100 kW have avoided cost prices that represent the true avoided cost for solar and wind projects; and (2) require the large developers to submit applications through Schedule 38 for multiple projects which would maintain.

Q. Please summarize the factors to be considered when setting the maximum nameplate capacity eligible for standard avoided cost prices.

A. The desire to stimulate QF development should be balanced with the mandate that customers not pay more for QF power than for other resources. The primary rationale for standard rates is to minimize transaction costs for small projects. Rates for larger projects should take individual operating characteristics into account. The desire to stimulate QF development must be balanced with the mandate that customers pay no more for QF power than a utility's avoided costs.

Q. Do you have a specific recommendation as to the appropriate capacity ceiling?

A. Yes. The Company proposes that 100 kW is a reasonable eligibility cap for wind and solar QF projects seeking Schedule 37 avoided cost prices and standard contracts. Setting the eligibility cap to 100 kW would continue to allow the development of QF resources across all resource types, while ensuring appropriate project characteristics are captured for all wind and solar resources to reflect true avoided costs.

Further, 100 kW is consistent with the transaction cost rationale for standard avoided cost rates and contract terms noted earlier in my testimony. Any projects over 100 kW would still receive avoided cost prices. However, prices would be calculated under a non-standard methodology that incorporates the PURPA adjustment factors for the specific project operating characteristics and providing the appropriate avoided cost prices.

CONCLUSION

Q. Please summarize your testimony and the Company's requested relief.

A. The Company is seeking implementation of a modification to the term of QF contracts and a reduction in the eligibility cap for standard avoided cost rates. These changes are necessary in order to maintain the ratepayer indifference standard required by PURPA and to protect Oregon customers. Specifically, the Company is requesting an order from the Commission directing implementation of a reduction of the maximum contract term for PURPA contracts from a 15-year fixed price term to a three-year fixed price term. The reduced term is consistent with Company's hedging and trading policies and practices for non-PURPA energy contracts and more aligned with the IRP cycle. The Company is also requesting an order from the Commission reducing the eligibility cap for wind and solar QF projects seeking Schedule 37 avoided cost prices and standard contracts.

The Company is seeking this relief as a result of a significant increase in

PURPA contract requests received in 2014 and 2015; activity that Pacific Power believes will harm customers unless the Commission directs modifications to the Company's current Oregon avoided cost contracts. As noted, the Company currently has pending requests for 587 MW of new PURPA contracts in Oregon, in addition to the 338 MW of executed contracts. By comparison, Pacific Power's minimum retail load in Oregon in 2014 was 1,027 MW. Across its six-state system, PacifiCorp currently has 4,017 MW of new PURPA contract requests, in addition to the 1,991 MWs of PURPA power already under contract. This striking increase in new QF activity exposes customers to higher price risk due to the sheer volume of power that may become locked in at a fixed price for decades under current QF PURPA contract terms.

The current Commission-approved PURPA contract length and high eligibility cap puts retail customers at risk of harm due to significant and unnecessary exposure to long-term price risk, a level of risk the Commission would not accept in the context of a non-PURPA transaction. The Company has no control over this price risk; 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.

The Company can mitigate the risk to customers of other long-term fixed price transactions both through term and capacity it purchases. The Company's practice since it completed the hedging collaborative workshops in 2012 has been to limit hedges to 36 months or less unless stakeholders express interest for longer term hedges. In the hedging collaborative workshop, stakeholders made it clear that they did not believe long-term gas hedges (and the corresponding long-term fixed-price risk) were in the best interest of customers. The 15-year maximum fixed price QF contract term goes against this conclusion reached by the collaborative stakeholders. For example, 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. But the Company is mandated to enter into a 15-year contract 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 not consistent with the hedging policy put in place as a direct result of input from stakeholders.

As explained above, transactions that exceed 36 months require extensive analysis and progressively higher level of management review. The primary reason that such a rigorous review process is necessary when entering into long-term transactions, and the reason the Company generally limits trading and hedging activities to the prompt 36 months, is that long-term fixed price energy contracts carry significant price risk. The market becomes more and more uncertain as you move further into the future, and it is difficult to forecast with reasonable certainty what prices will be far out into the future.

Moreover, the Company does not typically enter into long-term transactions unless those transactions have been identified as least-cost, least-risk transactions through the IRP process. Even then, the Company typically utilizes a rigorous RFP process to acquire any long-term resource identified by the IRP action plan. At this point in time, the Company does not have a need for a new long-term resource until

2028, and due to the timing of this need, the Company will not have any action items to procure a new long-term resource in the next two to four years.

The modification to the Company's current Oregon avoided cost contract term is required at this time to maintain the ratepayer indifference standard required by PURPA and to protect Oregon customers from ongoing harm.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UM ____
Exhibit PAC/101
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce W. Griswold

PPA and Pricing Requests as of May 1, 2015

May 2015

PacifiCorp's QF requests as of May 1, 2015

Location	Resource Type	Size (MW)	COD
Utah	Solar	1.0	12/31/2016
Utah	Solar	1.0	04/03/2016
Utah	Solar	80.0	11/01/2016
Utah	Solar	80.0	10/01/2016
Utah	Solar	80.0	01/01/2018
Utah	Solar	80.0	01/01/2018
Utah	Solar	21.0	01/01/2016
Utah	Solar	80.0	11/01/2016
Utah	Solar	10.0	12/31/2015
Utah	Solar	80.0	01/01/2016
Utah	Solar	20.0	10/01/2016
Utah	Solar	20.0	12/31/2016
Utah	Solar	40.0	12/31/2016
Utah	Solar	50.0	08/31/2015
Utah	Solar	15.0	12/31/2016
Utah	Solar	14.5	12/31/2016
Utah	Solar	7.5	12/31/2016
Utah	Solar	50.0	12/31/2016
Utah	Solar	80.0	12/31/2016
Utah	Solar	80.0	12/31/2016
Utah	Solar	6.0	12/31/2016
Utah	Solar	80.0	12/31/2015
Utah	Solar	80.0	12/31/2015
Utah	Solar	80.0	12/31/2015
Utah	Solar	80.0	11/01/2016
Utah	Solar	80.0	11/01/2016
Utah	Wind	45.0	11/01/2015
Utah	Wind	80.0	10/01/2015
Utah	Wind	69.0	12/31/2016
Utah	Wind	80.0	01/01/2018
Utah	Wind	80.0	01/01/2018
Utah	Solar	5.0	12/31/2015
Utah	Solar	78.2	12/31/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	40.0	12/01/2017
Utah	Solar	58.0	12/01/2016

Location	Resource Type	Size (MW)	COD
Wyoming	Wind	80.0	12/31/2016
Wyoming	Wind	80.0	12/31/2016
Wyoming	Wind	80.0	12/31/2016
Wyoming	Wind	72.6	09/01/2016
Wyoming	Wind	80.0	12/31/2016
Wyoming	Wind	80.0	12/31/2016
Wyoming	Wind	80.0	12/31/2016
Wyoming	Wind	80.0	12/31/2016
Wyoming	Wind	16.5	Renewal
Idaho	Gas	4.5	08/01/2015
Idaho	Solar	21.0	12/31/2016
Idaho	Solar	20.0	10/31/2016
Idaho	Solar	20.0	10/31/2016
Idaho	Solar	20.0	12/31/2016
Idaho	Solar	20.0	12/31/2016
Idaho	Solar	20.0	12/31/2016
Idaho	Solar	20.0	12/31/2016
Idaho	Solar	40.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	50.0	08/01/2016
Idaho	Hydro	0.3	04/01/2016
Idaho	Wind	20.0	12/01/2017
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	80.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2015
Oregon	Solar	10.0	12/31/2015
Oregon	Solar	5.0	12/31/2015
Oregon	Solar	7.5	12/31/2015
Oregon	Solar	10.0	12/31/2015
Oregon	Solar	10.0	12/31/2015
Oregon	Solar	8.0	12/31/2015
Oregon	Solar	10.0	12/31/2015
Oregon	Solar	10.0	12/31/2015
Oregon	Solar	9.9	12/31/2016

Location	Resource Type	Size (MW)	COD
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	3.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	6.0	12/31/2016
Oregon	Solar	3.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Geothermal	3.5	05/01/2014
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	45.0	12/31/2016
Oregon	Solar	20.0	12/31/2016
Oregon	Solar	44.2	01/01/2017
Oregon	Solar	80.0	12/31/2016
Oregon	Solar	10.0	12/1/2016
Oregon	Solar	10.0	12/1/2016
Oregon	Solar	10.0	12/1/2016
Oregon	Solar	10.0	12/1/2016
Oregon	Solar	8.0	12/1/2016
Oregon	Solar	10.0	12/1/2016
Oregon	Solar	10.0	12/1/2016
Oregon	Solar	10.0	12/1/2016
Oregon	Solar	8.0	12/31/2017
Oregon	Solar	2.9	12/31/2017
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016

Docket No. UM ____
Exhibit PAC/102
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce W. Griswold

Schedule 37 Solar PPA Requests Since January 1, 2014

May 2015

Oregon Schedule 37 QF PPA Requests in 2014 and 2015

Size (MW)	Initial Request for PPA	COD
10.0	03/14/2014	12/31/2016
3.0	03/28/2014	12/31/2015
10.0	03/28/2014	12/31/2015
10.0	03/28/2014	12/31/2015
5.0	04/09/2014	12/31/2015
7.5	04/09/2014	12/31/2015
10.0	04/09/2014	12/31/2015
10.0	04/14/2014	12/31/2015
10.0	04/14/2014	12/31/2015
8.0	04/15/2014	12/31/2015
10.0	04/15/2014	12/31/2015
10.0	04/15/2014	12/31/2015
10.0	05/04/2014	12/31/2015
6.0	05/15/2014	12/31/2015
10.0	07/07/2014	12/31/2015
9.9	07/30/2014	12/31/2016
9.9	07/31/2014	12/31/2016
9.9	08/01/2014	12/31/2016
8.0	08/07/2014	12/31/2016
0.8	08/11/2014	12/31/2015
2.8	08/15/2014	12/31/2016
8.0	08/15/2014	12/31/2016
9.9	08/18/2014	12/31/2016
9.9	08/18/2014	12/31/2016
10.0	04/23/2015	12/1/2016
10.0	04/23/2015	12/1/2016
10.0	04/23/2015	12/1/2016
10.0	04/23/2015	12/1/2016
8.0	04/23/2015	12/1/2016
10.0	04/23/2015	12/1/2016
10.0	04/24/2015	12/1/2016
8.0	04/27/2015	12/31/2017
10.0	04/29/2015	12/1/2016
2.9	04/29/2015	12/31/2017
10.0	05/04/2015	12/31/2016
10.0	05/04/2015	12/31/2016
10.0	05/04/2015	12/31/2016

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Application to Reduce the Qualifying Facility Contract Term Eligibility Cap on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

Service List
Docket UM 1610

Renee M. France
Oregon Department of Justice
Natural Resources Section
1162 Court St NE
Salem, OR 97301-4096
renee.m.france@doj.state.or.us

Matt Krumenauer
Senior Policy Analyst
Oregon Department of Energy
625 Marion St NE
Salem, OR 97301
matt.krumenauer@state.or.us

Diane Broad
Senior Policy Analyst
Oregon Department of Energy
625 Marion St NE
Salem, OR 97301
diane.broad@state.or.us

Donovan E. Walker
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
dwalker@idahopower.com

Julia Hilton
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
jhilton@idahopower.com

J. Richard Geaorge
Portland General Electric Company
121 SW Salmon St. – 1WTC1301
Portland, OR 97204
richard.george@pgn.com

Lisa F. Rackner
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
dockets@mcd-law.com

Jay Tinker
Portland General Electric Company
121 SW Salmon St. – 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com

V. Denise Saunders
Portland General Electric Company
121 SW Salmon St. – 1WTC1301
Portland, OR 97204
denise.saunders@pgn.com

Renewable NW Dockets
Renewable Northwest
421 SW 6th Ave., Ste. 1125
Portland, OR 97204
dockets@renewablenw.org

Brittany Andrus
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
brittany.andrus@state.or.us

Will K. Carey
Annala, Carey, Baker, Et Al., PC
PO Box 325
Hood River, OR 97031
wcarey@gorge.net

Stephanie S. Andrus
PUC Staff – Department of Justice
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4096
stephanie.andrus@state.or.us

Richard Lorenz
Cable Houston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Ave, Suite 2000
Portland, OR 97204-1136
rlorenz@cablehuston.com

Megan Decker
Renewable Northwest
421 SW 6th Ave., Ste. 1125
Portland, OR 97204
megan@renewablenw.org

Robert Jenks
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
bob@oregoncub.org

Mike McArthur
Executive Director
Association of OR Counties
PO Box 12729
Salem, OR 97309
mmcarthur@aocweb.org

David Tooze
City of Portland – Planning & Sustainability
1900 SW 4th Suite 7100
Portland, OR 97201
David.tooze@portlandoregon.gov

Chad M. Stokes
Cable Houston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Ave, Suite 2000
Portland, OR 97204-1136
cstokes@cablehuston.com

Thad Roth
Energy Trust of Oregon
421 SW Oak Street, #300
Portland, OR 97204-1817
thad.roth@energytrust.org

OPUC Dockets
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
dockets@oregoncub.org

Kenneth Kaufmann
Lovinger Kaufmann LLP
825 NE Multnomah, Suite 925
Portland, OR 97232-2150
Kaufmann@lklaw.com

Sommer Templet
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
sommer@oregoncub.org

Daren Anderson
Northwest Energy Systems Company LLC
1800 NE 8th Street, Suite 320
Bellevue, WA 98004-1600
da@thenescogroup.com

Diane Henkels
Cleantech Law Partners PC
6228 SW Hood
Portland, OR 97239
dhenkels@cleantechlawpartners.com

OSEIA Dockets
Oregon Solar Energy Industries Association
PO Box 14927
Portland, OR 97293
dockets@oseia.org

Tyler C. Pepple
Davison Van Cleve
333 SW Taylor, Suite 400
Portland, OR 97204
tcp@dvclaw.com

S. Bradley Van Cleve
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
bvc@dvclaw.com

John M. Volkman
Energy Trust of Oregon
421 SW Oak Street, #300
Portland, OR 97204-1817
john.volkman@energytrust.org

John Harvey
Exelon Wind LLC
4601 Westown Parkway, Suite 300
Wet Des Moines, IA 50266
John.harvey@exeloncorp.com

Jeffrey S. Lovinger
Lovinger Kaufmann LLP
825 NE Multnomah, Suite 925
Portland, OR 97232-2150
lovinger@lklaw.com

Bill Eddie
One Energy Renewables
206 NE 28th Avenue
Portland, OR 97232
Bill@oneenergyrenewables.com

Kathleen Newman
Oregonians for Renewable Energy Policy
1553 NE Greensword Drive
Hillsboro, OR 97214
k.a.newman@frontier.com

R. Bryce Dalley
Pacific Power
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
Bryce.dalley@pacificorp.com

Mark Pete Pengilly
Oregonians for Renewable Energy Policy
PO Box 10221
Portland, OR 97296
mpengilly@gmail.com

Dustin Till
Pacific Power
825 NE Multnomah Street, Suite 1800
Portland, OR 97232
dustin.till@pacificorp.com

Gregory M. Adams
Richardson & O'Leary
PO Box 7218
Boise, ID 83702
greg@richardsonadams.com

Toni Roush
Roush Hydro Inc
366 E Water
Stayton, OR 97383
tmroush@wvi.com

David A Lokting
Stoll Berne
209 SW Oak Street, Suite 500
Portland, OR 97204
dlokting@stolberne.com

Thomas H. Nelson
Attorney at Law
PO Box 1211
Welches, OR 97067-1211
nelson@thenelson.com

Loyd Fery
11022 Rainwater Lane SE
Aumsville, OR 97325
dlchain@wvi.com

David Brown
Obsidian Renewables, LLC
5 Centerpointe Dr. Ste 590
Lake Oswego, OR 97035
dbrown@obsidianrenewables.com

Oregon Dockets
PacifiCorp dba Pacific Power
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
Oregondockets@pacificorp.com

Todd Gregory
Obsidian Renewables, LLC
5 Centerpointe Dr. Ste 590
Lake Oswego, OR 97035
tgregory@obsidianrenewables.com

John Lowe
Renewable Energy Coalition
12050 SW Tremont Street
Portland, OR 97225-5430
jravenesanmarcos@yahoo.com

Paul Ackerman
Exelon Business Services Company, LLC
100 Constellation Way Ste 500C
Baltimore, MD 21202
Paul.ackerman@constellation.com

Peter J. Richardson
Richardson & O'Leary PLLC
PO Box 7218
Boise, ID 83702
peter@richardsonadams.com

James Birkelund
Small Business Utility Advocates
548 Market Street, Suite 11200
San Francisco, CA 94104
james@utilityadvocates.org

Irion Sanger
Sanger Law PC
1117 SE 53rd Ave
Portland, OR 97215
irion@sanger-law.com

Brian Skeahan
CREA
PMB 409
18160 Cottonwood Rd
Sunriver. OR 97707
Brian.skeahan@yahoo.com

Betsy Kauffman
Energy Trust of Oregon
421 SW Oak Street, #300
Portland, OR 97204-1817
betsy.kauffman@energytrust.org

Dated this 21st day of May, 2015.

Amy Eissler
Coordinator, Regulatory Operations

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Application to Reduce the Qualifying Facility Contract Term on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

Service List
Docket UM 1725

Shao-Ying Mautner
Foley & Lardner
3000 K Street NW, Suite 600
Washington DC 20007
smautner@foley.com

Thomas McCann Mullooly
Foley & Lardner
3000 K Street NW, Suite 600
Washington DC 20007
tmullooly@foley.com

Kurt Rempe
Foley & Lardner
3000 K Street NW, Suite 600
Washington DC 20007
krempe@foley.com

Donovan E. Walker
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
dwalker@idahopower.com

Christa Bearry
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
cbearry@idahopower.com

Rob MacFarlane
Portland General Electric Company
121 SW Salmon St. – 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com

Lisa F. Rackner
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
dockets@mcd-law.com

Dustin Till
Pacific Power
825 NE Multnomah Street, Suite 1800
Portland, OR 97232
dustin.till@pacificorp.com

Denise Saunders
Portland General Electric Company
121 SW Salmon St. – 1WTC1301
Portland, OR 97204
denise.saunders@pgn.com

Ryan Meyer
Pacific Northwest Solar
8221 King Rd.
Loomis, CA 95650
Ryan.meyer@pacificnorthwestsolar.net

Brittany Andrus
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
brittany.andrus@state.or.us

Oregon Dockets
PacifiCorp dba Pacific Power
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
Oregondockets@pacificorp.com

Stephanie S. Andrus
PUC Staff – Department of Justice
Business Activities Section

John Lowe (W)
Renewable Energy Coalition
12050 SW Tremont Street

1162 Court St. NE
Salem, OR 97301-4096
stephanie.andrus@state.or.us

Portland, OR 97225-5430
jravenesanmarcos@yahoo.com

Irion Sanger (W)
Sanger Law PC
1117 SE 53rd Ave
Portland, OR 97215
irion@sanger-law.com

Dated this 21st day of May, 2015.

Amy Eissler
Coordinator, Regulatory Operations