ROCKY MOUNTAIN
POWER
A DIVISION OF PACIFICORP

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February 27, 2015

OVERNIGHT DELIVERY

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

Attention: Jean D. Jewell
Commission Secretary

RE: CASE NO. PAC-E-15-03
IN THE MATTER OF THE PETITION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS AND FOR MODIFICATION OF ITS AVOIDED COST METHODOLOGY

Please find enclosed for filing an original and nine copies of Rocky Mountain Power's Petition in the above-referenced matter, along with nine copies of the direct testimony and exhibit. Also enclosed is a CD containing the Petition, testimony and exhibit.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

Very truly yours,

Jeffrey K Larsen / NCS

Jeffrey K. Larsen
Vice President, Regulation

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Attorneys for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS AND FOR MODIFICATION OF ITS AVOIDED COST METHODOLOGY	**CASE NO. PAC-E-15-03** **PETITION OF ROCKY MOUNTAIN POWER**

I. INTRODUCTION AND SUMMARY

Rocky Mountain Power, a division of PacifiCorp ("Company" or "Rocky Mountain Power"), submits this Petition for Modification of Terms and Conditions of PURPA Purchase Agreements and for Modification of Its Avoided Cost Methodology under RP 53. In this Petition, the Company asks the Idaho Public Utility Commission ("Commission") for: (1) immediate relief from certain terms and conditions of its prospective contracts with qualifying facilities ("QFs") under the federal Public

Utility Regulatory Policies Act of 1978 ("PURPA"); and (2) long-term modifications to PURPA contract terms and conditions going forward.

The Company has experienced a significant increase in new QF requests in the immediate wake of the Commission's Order 33222, issued February 6, 2015 in Case No. IPC-E-15-01, which temporarily reduced Idaho Power Company's ("Idaho Power") PURPA contract length from 20 years to five years. These new requests, combined with the large number of existing requests and already executed PURPA contracts, prompts the Company's current expedited request for similar treatment from the Commission in this proceeding, which would be consistent with previous Commission orders issued under almost these precise circumstances. In addition to the immediate, temporary relief, the Company, like Idaho Power, has experienced a significant increase in PURPA contract requests in 2014 and 2015, activity that Rocky Mountain Power believes will harm customers unless the Commission directs permanent modifications to the Company's current Idaho avoided cost contracting and pricing procedures in the long term.

Idaho Power's pending petition in Case No. IPC-E1-15-01 describes the new flood of requests on Idaho Power's system in recent years related to the rapid development of solar QFs in the state. The Commission has recently expressed concern about passing the costs of these unneeded resources onto Idaho retail customers and Idaho Power's ability to continue taking such large amounts of intermittent generation on its system. In its Idaho Power Order, the Commission found, upon initial review of Idaho Power's petition, that its concerns about the influx of QF power continue "unabated."[1] The Commission concluded, "there is sufficient evidence that the predicted influx of high-capacity PURPA contracts could significantly and

[1] Commission Order 33222 at 4.

detrimentally impact customer rates and system reliability."[2] For that reason, the Commission immediately and temporarily reduced the maximum QF contract term for Idaho Power's QF contracts from 20 years to five years.[3]

These same concerns, as well as the new flood of QF requests in the wake of Commission Order 33222, inform the Company's present petition. Similar to Idaho Power, the Company has experienced a significant increase in QF pricing requests in Idaho and across its six-state system. Similar to Idaho Power, the Company has no need for resources in the next decade.[4] Similar to Idaho Power, the Company's hedging practices are short-term in nature. Given the magnitude of new QF requests, and considering the inherent uncertainties in projecting avoided cost rates out 20 years or more, current Idaho avoided costs rates are adversely impacting customers and will continue to do so for 20 years.

A. Purpose of Filing

The Company is seeking an order from the Commission directing the Company to implement the following changes to its PURPA contracting procedures:

1. Immediate reduction, on a temporary basis, of the maximum contract term for PURPA contracts between QFs and the Company from 20 years to five years, pending litigation of this case.
2. Permanent reduction of the maximum contract term for PURPA contracts from 20 years to three years to be consistent with the Company's hedging and trading policies

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[2] *Id.*
[3] *Id.*
[4] PacifiCorp's 2013 IRP Update filed with the Commission shows that new long-term resources are not required until 2027. PacifiCorp's 2015 IRP, which is scheduled to be filed in March 2015, will show no new resource need until 2028.

and practices for non-PURPA energy contracts and more aligned with the Integrated Resource Plan ("IRP") cycle.

3. Modification of the Company's avoided cost methodology such that preparation of indicative pricing for QFs reflects all active QF projects in the pricing queue ahead of any newly proposed QF requests for indicative pricing. This change updates a modeling assumption that, in light of recent FERC precedent, will result in purchase obligations based on indicative pricing that will not reflect then-current avoided costs unless it is corrected.

The Company seeks immediate relief on the first item in order to protect its customers in the near term. The Company is seeking permanent implementation of the remaining two modifications to QF contracting and pricing procedures in the long term.

B. Need for Immediate, Temporary Relief

The Company is seeking immediate changes to its PURPA contracts terms and conditions for two primary reasons: (1) the effect of the Commission's order reducing Idaho Power's PURPA contract length and (2) the Company's already large number of potential and existing Idaho PURPA obligations.

First, the Company and our customers are being immediately and negatively affected by the Commission's order reducing Idaho Power's PURPA contract length from 20 years to five years, and therefore Company seeks expedited and temporary relief on that basis. Indeed, within five days of Commission Order 33222, the Company received four pricing requests totaling 130 megawatts ("MW") from QF developers who are located in Idaho Power's service territory but are now planning to obtain a transmission wheel to PacifiCorp in order to secure a more favorable 20-year contract with the Company.[5]

These requests bring the total amount of proposed Idaho PURPA projects currently seeking contracts with PacifiCorp to 275.5 MW. Add to the 275.5 MW of proposed projects the 189.6 MW of Idaho PURPA contracts already executed by PacifiCorp, and the Company has a total of 465.1 MW of existing and proposed PURPA purchase obligations in Idaho. This amount, at full nameplate capacity, would be enough to supply 108 percent of PacifiCorp's average Idaho retail load in 2014 and 275 percent of PacifiCorp's minimum Idaho retail load in 2014.[6]

Because of the disparity created by the Idaho Power Order and the large number of potential and existing Idaho PURPA obligations, both of which have the capability to immediately harm the Company's retail customers, the Company seeks an expedited order temporarily lowering the Company's power purchase agreement ("PPA") term from 20 years to five years. Such an order would be consistent with the previous Commission orders issued under almost these precise circumstances. In particular, in 1996 and 1997, the Commission issued orders shortening QF contract lengths from 20 years to five years for Idaho Power.[7] PacifiCorp then filed a petition with the Commission requesting the same tenor reduction in order to prevent the disparate treatment and competitive disadvantage that would result if it were required to continue offering 20 year contracts.[8] Commission Staff supported PacifiCorp's request, stating its belief that "rules regarding contract

[5] The Company has reviewed Idaho Power's Open Access Same Time Information System and confirmed that transmission is available to enable these wheels. Such wheels are permitted under PURPA. FERC's rules and orders contemplate that if a QF interconnects with one utility and wheels power to another utility's system, the second utility is required to purchase that power. *See* 18 CFR § 292.303 (2014).

[6] PacifiCorp's average Idaho retail load in 2014 was 432 MW, and the minimum Idaho retail load was 169 MW.

[7] *See In re Application of Idaho Power Company*, Case No. IPC-E-95-9, Order No. 26576 (Sept.1996); *In re Application of Idaho Power Company*, Case No. IPC-E-97-9, Order No. 27111 (Aug. 1997);

[8] *In re Application of PacifiCorp dba Utah Power & Light Company*, Case No. UPL-E-97-4.

length for PURPA contracts should be the same for all regulated electric utilities in Idaho to avoid disparate treatment."[9] The Commission adopted Commission Staff's position and granted PacifiCorp's request in that proceeding.[10] The Company seeks the same relief in this Petition in order to ensure all Idaho retail customers are treated equally.

C. Need for Permanent, Long-Term Relief

The Company has reviewed its PURPA contracts and believes that permanent, long-term changes to its PURPA contracts are also critical to maintain the ratepayer indifference standard required by PURPA and to the welfare of the Company's Idaho retail customers. The Commission has made clear that the utilities are in the best position to advise the Commission when changes to PURPA contract terms and conditions are warranted:

> While we are pleased with the progression of the IRP methodology, avoided cost rates are not the only terms to a PURPA contract. The utilities are in the best position to inform the Commission if review of additional PURPA contract terms and conditions is warranted.[11]

Rocky Mountain Power routinely reviews its PURPA contract terms and conditions and avoided cost methodologies, and recent events dictate that the Company petition this Commission for two long-term changes now: (1) a permanent reduction of the maximum contract term for PURPA contracts from 20 years to three years; and (2) a requirement that indicative prices for newly proposed QFs reflect all active QF projects in the PacifiCorp system QF pricing queue.

1. Permanent Reduction in Contract Length from 20 years to Three Years

Like Idaho Power, the Company has been experiencing a significant increase in the

[9] Case No. UPL-E-97-4, Order No. 27213 (Nov. 1997).
[10] *Id.*
[11] *In re Application of Idaho Power Company,* Case No. IPC-E-14-30; Order No. 33204 at 8 (Jan. 8, 2015).

number of QF pricing requests both in Idaho and across its six-state system, including a significant increase in Idaho QF requests after Commission Order 33222. To that end, the Company experienced a surge in PURPA contract requests in 2014 and 2015. Not only do requests continue to come in, but they have now increased even further due to the migration of QFs from Idaho Power's service territory in light of Commission Order 33222. PacifiCorp currently has pending requests for 275.5 MW of new PURPA contracts in Idaho, in addition to the 189.6 MW of existing contracts. Across its six-state system, PacifiCorp currently has 3,641 MW of new PURPA contract requests, in addition to the 1,732 MWs of PURPA power already under contract. Given the large quantity of existing and new QF requests, and considering the inherent uncertainties in projecting avoided cost rates out 20 years or more, current Idaho avoided cost rates are adversely impacting retail customers. The Company therefore seeks a permanent reduction in PPA contract length to mitigate price risk to its customers.

2. Indicative Pricing Reflecting All Active QF Projects Ahead of Any Newly Proposed QF Requests in the Pricing Queue

The Company also reviewed the impact of the significant increase in proposed PURPA contracts on avoided costs in Idaho and determined that the currently approved requirement that the Company's avoided cost rate modeling can only be updated to account for signed QF contract commitments will result in PURPA purchase obligations that are based on indicative pricing that becomes inaccurate and cannot be updated prior to the QF entering into a purchase obligation. This requirement effectively prices each QF project as if it is first in the queue, regardless of how many other projects previously requested pricing and are still actively negotiating contracts.

However, the Federal Energy Regulatory Commission ("FERC") recently issued a series of orders clarifying that a state may not require a QF to obtain a signed contract as a precondition to obtaining a legally enforceable obligation ("LEO"). In light of this precedent, the current first-in-the-queue pricing requirement results in inaccurate indicative pricing, which is then required to be used in final contracts, because each QF project may be entitled to a LEO before the Company is permitted to update its indicative avoided cost rates (*i.e.*, upon signing). This pricing requirement artificially inflates the Company's avoided cost pricing for QFs who are not first in the queue (or first to enter into a purchase obligation) and thus harms retail customers. This methodology will result in Commission-approved avoided cost calculations that will not accurately reflect the incremental costs to the Company of energy and capacity, unless the methodology is corrected. The Company therefore also requests the Commission direct that the preparation of indicative pricing for QFs must reflect all active QF projects in the pricing queue ahead of any newly proposed QF requests for indicative pricing.

D. Support for the Company's Petition

The Company's petition is supported by the testimony of the following witnesses:

1. Paul H. Clements will provide an overview of the Company's petition and discuss the size of the current QF pricing queue and its impact on Idaho customers, the risks associated with long-term fixed price contracts, and how long-term PURPA contracts are inconsistent with the Company's hedging policies and practices and the Company's resource planning and acquisition practices through the IRP process.

2. Brian S. Dickman will outline the impact of the large Idaho QF pricing queue on avoided costs in Idaho and the determination that the currently approved methodology distorts avoided cost pricing because each project must be priced as if it were first in the queue.

E. Idaho Power Company's Petition

Idaho Power's pending petition in Case No. IPC-E1-15-01 not only asks the Commission to reduce PURPA contract length for Idaho Power, but also asks the Commission to examine and potentially revise certain other issues related to the commission's implementation of PURPA. These items could include:

- Further modification to the existing avoided cost pricing methodologies to more appropriately reflect need and resource sufficiency in the price;
- Implementation of new avoided cost pricing methodologies which move to a market based or competitively bid-based avoided cost mechanism, such as that utilized in Washington;
- Exemption from PURPA under § 210(m);
- Commission pursuit of a waiver from the requirements of § 210, subpart C, for Idaho Power pursuant to 18 C.F.R. § 292.402;
- Refinement of the Commission's 90%/110% definition of firmness to require firm scheduled deliveries or entitlement to rates established at the time of contracting or legally enforceable obligation, as opposed to rates determined at the time of delivery, similar to the implementation in Texas;
- Further refinement of the eligibility for rates established at the time of contracting or legally enforceable obligation by requiring QFs to be within 90 days of delivering power before the utility is obligated to the price, again similar to the implementation in Texas;
- Modification of contractual term limitations; and

- Establishment of caps, or MW targets, upon the amount of new or repowered projects a utility is required to procure over a given period of time, similar to those in place in California.

The Company would support the Commission's examination of these issues and any other issues necessary to maintain the ratepayer indifference standard required by PURPA. The Company is not requesting the Commission review these issues as part of this proceeding, however the Company requests the opportunity to present evidence in support of any or all of these issues at the appropriate time in the appropriate proceeding.

II. 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.[12] 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 incremental cost to the electric utility of alternative electric energy."[13] The

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[12] *See, e.g.,* 16 U.S.C. § 2601 (Findings).
[13] 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.

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.[14] 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 in the absence of the QF purchase.[15]

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 incremental cost requirement.[16] While the applicable statutes and rules are matters of federal law, PURPA gives to state regulatory authorities the responsibility of determining a utility's avoided costs as well as terms and conditions of PURPA contracts.[17]

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. This Commission stated as early as 1987 that,

> Under current FERC regulations implementing the Public Utility Regulatory Policies Act, ratepayers are supposed to be indifferent or neutral as to whether they receive energy through a QF or a regulated

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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.

[14] 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.

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

[16] *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).

[17] *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)).

> utility. Stated differently, the price structure should enable utilities to integrate in a neutral and unbiased manner both utility and non-utility owned generating facilities into the long-run planning process and should provide similar economic criteria for development and operation of generating facilities regardless of facility ownership.[18]

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."[19] 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.[20]

Under PURPA, then, customers must remain indifferent or unaffected by QF contracts. Further, as this Commission has noted, "avoided cost rates are not the only terms to a PURPA contract."[21] 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 modifications requested by the Company in this petition are necessary to maintain this ratepayer indifference standard and are the primary means by which the Company and the Commission can protect customers from unnecessary price risk.

B. This Commission Has the Authority to Determine the Appropriate Contract Term for Qualifying Facilities to Receive Under PURPA

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[18] *In re Review of the Idaho Pub. Utils. Comm'n Policies Establishing Avoided Costs Under the Pub. Util. Regulatory Policies Act of 1978*, Case No. U-1500-170, Order No. 21249 (May 1987).
[19] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at 62,080 (1995) *overruled on other grounds, Cal Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010).
[20] *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.").
[21] Order No. 33204 at 8.

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.[22]

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."[23] 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.[24] 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."[25]

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

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[22] *Idaho Power Co.*, 155 Idaho 780 at 782; *Exelon Wind I, LLC*, 766 F.3d 380 (5th Cir. 2014).
[23] 18 C.F.R. § 292.304(d)(2).
[24] *See, e.g.*, *Idaho Power Co.*, 155 Idaho 780, 782; *Cuero Hydroelectric, Inc. v. The City of Cuero, Tex.*, 85 FERC ¶ 61,124 at 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 at 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.").
[25] *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059 at P 24 (2010).

cost rates for the entire contract term.[26] FERC has explained that it believes imperfections found in the avoided cost methodology should, if set correctly, balance out between overestimation and underestimations.[27] However, PURPA and FERC regulations are silent as to the length of QF contracts and, with a few exceptions not relevant here,[28] 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.[29] 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."[30] 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. Initially, the Commission set PURPA contracts at 35 years

[26] *See Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA*, 45 Fed. Reg. 12214, 12224 (1980).
[27] *Id.*
[28] 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.
[29] *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.").
[30] *Exelon Wind I, LLC*, 766 F.3d at 396.

to match the amortization period allowed for similar utility owned facilities, making financing easier, thus encouraging QF development.[31] Later, the Commission began to recognize concerns related to the risk and uncertainty inherent in long range forecasting and shortened the contract length to 20 years.[32] This time frame was shortened to only five years in 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.[33] The 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."[34] In 2002, the Commission raised the contract length back to 20 years, expressing concerns about a scarcity of QF contracts signed since the prior change.[35]

Since the 2002 order, concerns regarding the viability of QFs are no longer at the forefront. In 2015, the key concerns about PURPA contracts are similar to those that were present at the time of the Commission's 1996 and 1997 orders reducing the term to five years, *i.e.*, the current concerns flow 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 the Commission noted in a recent press release, the Commission has

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[31] *See, e.g,. In re Investigation of the Continued Reasonableness of Current Size Limitations for PURPA QF Published Rate Eligibility and Restrictions on Contract Length,* Case No. GNR-E-02-1, Order No. 29029 at 2 (May 2002) (describing the origin of PURPA regulation in Idaho).

[32] *In re Review of the Idaho Public Utilities Commission's Policies Establishing Avoided Costs under PURPA*, Case No. U-1500-170, Order No. 21630 (Dec. 1987).

[33] See Order No. 26576; Order No. 29029 at 5 (describing the history of PURPA regulation in Idaho).

[34] Order No. 26576 at 13.

[35] See Order No. 29029 at 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.").

approved PURPA contracts for 400 MW of solar energy in just the past three months.[36] But the Commission noted, "PURPA does not address and FERC regulations do not adequately provide for consideration of whether the utility being forced to purchase QF power is actually in need of such energy."[37] The Commission has repeatedly expressed concerns about price and reliability impacts on Idaho customers in the past year, concerns that led the Commission to lower the approved length of PURPA contracts for Idaho Power down to five years in Commission Order 33222.[38]

III. DISCUSSION

A. The Commission Should Immediately Reduce, on a Temporary Basis, the Maximum Contract Term for PURPA Contracts Between QFs and the Company from 20 Years to Five Years While this Docket Is Litigated.

The Company is being immediately and negatively affected by the Commission's order reducing Idaho Power's PURPA contract length from 20 years to five years and the recent influx of PURPA contract requests, and seeks expedited and temporary relief on that basis. Already, 130 MW of QFs that would have otherwise sought contracts with Idaho Power are seeking to wheel power from Idaho Power's system to PacifiCorp's system in order to secure a more favorable 20-year contract with PacifiCorp. Within five days of Commission Order 33222, PacifiCorp received four pricing requests totaling 130 MW from PURPA developers who are located in Idaho Power's service territory but now intend to wheel power to PacifiCorp's system in search of an off-taker for their energy who is required to offer a QF contract with more favorable terms.[39] Because of this arbitrage, which could potentially cause immediate harm to the Company's retail customers, the

[36] Press Release, Idaho Public Utilities Commission, PUC reduces length of some PURPA contracts to five years (Feb. 5, 2015).
[37] Order No. 33204 at 7.
[38] *See, e.g.*, Commission Order 33222 at 4.
[39] Direct Testimony of Paul H. Clements at p. 4, lines 14-18 ("Clements Testimony").

Company seeks an expedited order temporarily lowering the Company's QF contract term from 20 years to five years.

The Commission has previously recognized that the significant number of QF requests that utilities often receive during times of change in Commission PURPA policy is not in the public interest, and has even gone as far as to temporarily suspend Idaho utilities' mandatory purchase obligation under PURPA while the Commission resolved issues in an open docket. For example, in a case involving the review of certain avoided cost rate methodology issues, the Commission found that "[p]rior experience of the Commission teaches us that whenever potential qualifying facilities sense a pending change in the Commission's policy with respect to prices, there is a flood of applications seeking to obtain contracts at the existing rates."[40] The Commission concluded that such a rush of requests was not in the public interest because: (1) all of its regulated utilities were experiencing excess capacity and there was no immediate or compelling need to obtain additional capacity in the short term; (2) speculative projects that can be developed quickly would be encouraged at the expense of more serious projects that might take longer to develop; and (3) there was no clear indication that customers would benefit.[41] As a result, the Commission found that it was in the public interest to "suspend the compelled execution of new contracts and approval of contracts" for seven months or until the end of the Commission's investigation (whichever came first) so the Commission could "approach these serious issues in a deliberate manner, free from litigation and disputes with respect to proposed contracts."[42]

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[40] Order No. 21249, at 8, n.6 (also noting that "[o]n one occasion, when during the course of a contested hearing, it became apparent that the Commission might announce its decision regarding avoided costs from the bench, numerous applications were filed with the Commission within a few hours.").
[41] *Id.* at 8-9.
[42] *Id.* at 9.

The flood of QF requests that PacifiCorp has received since Commission Order 33222 resulted from a change in PURPA contract term policy rather than avoided cost pricing policy, but it has nevertheless had – and will continue to have – the similar impacts that are not in the public interest until the Commission takes action. As noted above, the Commission has the authority to determine the appropriate term for QF contracts, and it has exercised this authority to raise and lower the contract term for PURPA contracts as it deemed appropriate since PURPA's inception. In fact, the Commission has previously granted a request by PacifiCorp to reduce its PURPA contract term under almost the precise circumstances at issue here. In 1996 and 1997, the Commission issued orders shortening QF contract lengths from 20 years to five years for Idaho Power.[43] PacifiCorp then filed a petition with the Commission requesting the same tenor reduction in order to prevent the disparate treatment and competitive disadvantage that would result if it were required to continue offering 20 year contracts.[44] Commission Staff supported PacifiCorp's petition, stating its belief that "rules regarding contract length for PURPA contracts should be the same for all regulated electric utilities in Idaho to avoid disparate treatment."[45] The Commission granted PacifiCorp's request in that proceeding,[46] and should do the same here based on the same rationale.

B. The Commission Should Direct the Company to Make Long-Term Changes to Its PURPA Contract Terms and Conditions and Avoided Cost Methodology to Protect Customers from Undue Price Risk and to Maintain Customer Indifference to the Purchase of QF Power

Increasing levels of QF generation are exposing customers to progressively higher levels of risk, warranting immediate Commission action to protect customers. To ensure the ratepayer indifference standard is maintained, the Commission should permanently reduce the maximum

[43] *See* Order Nos. 26576, 27111.
[44] Case No. UPL-E-97-4.
[45] Order No. 27213.
[46] *Id.*

contract term for PURPA contracts from 20 years to three years, and modify the avoided-cost methodology governing indicative pricing in light of recent FERC precedent that renders the current methodology untenable. These steps are critical to ensuring that resources procured on behalf of retail customers are as low-cost and as low-risk as possible.

1. Increasing levels of QF generation are exposing customers to progressively higher levels of risk, warranting immediate Commission action to protect customers

A dramatic increase in PURPA contract requests in the last two years is driving the Company's request for additional review of contract and pricing methodology for non-standard Idaho QFs (i.e. those who are not eligible for published rates). 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 Commission contract terms; moreover, the greater the volume of power locked-in at long-term contract rates, the higher the magnitude of potential harm to PacifiCorp customers.

PacifiCorp currently manages 141 PURPA contracts totaling 1,732 MW of nameplate capacity across its six-state system. Of this total, 97 projects totaling 1,553 MW (90 percent of the total PURPA MWs 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, 47 projects totaling 885 MW (slightly more than half of the total PURPA MWs) 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. In Idaho, four projects totaling 167.4 MW came online in 2011 and 2012. Those four projects alone are close in nameplate capacity to the Company's minimum Idaho retail load in 2014 of 169 MW.[47]

PacifiCorp currently has twelve project requests totaling 275.5 MW of proposed PURPA contracts in Idaho. PacifiCorp currently has requests from 89 projects totaling 3,641 MW of nameplate capacity system-wide.[48] Table 1 shows the number of project requests and the total MWs by resource type for each of PacifiCorp's six states:[49]

Table 1

State	Wind		Solar		Other		Total	
	Projects	MWs	Projects	MWs	Projects	MWs	Projects	MWs
California								
Idaho			11.0	271.0	1.0	4.5	12.0	275.5
Oregon			25.0	312.4	1.0	3.5	26.0	315.9
Utah	5.0	354.0	38.0	2,075.6			43.0	2,429.6
Washington								
Wyoming	8.0	620.0					8.0	620.0
TOTAL	**13.0**	**974.0**	**74.0**	**2,659.0**	**2.0**	**8.0**	**89.0**	**3,641.0**

In Idaho, PacifiCorp has 189.6 MW of existing PURPA contracts and 275.5 MW of proposed PURPA contracts, together totaling 465.1 MW of nameplate capacity.[50] Using 2014 as an example, PacifiCorp's maximum total retail load in Idaho was 818 MW, its minimum load was 169 MW, and its average load was 432 MW. The 465.1 MW of existing and proposed PURPA contracts in Idaho at their nameplate capacity would be enough to supply 108 percent of PacifiCorp's average Idaho retail load and 275 percent of PacifiCorp's minimum retail load.[51]

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47 *See* Clements Testimony at p. 14.
48 *Id.* at p. 15.
49 In addition, Exhibit 1 to the Clements Testimony provides detailed information on the pricing queue, including each project size, location (state), and proposed online date. Project names have been withheld to maintain confidentiality of the customer information.
50 Clements Testimony at p. 15.
51 *See id.* at pp. 15-16.

System-wide, PacifiCorp has 1,732 MW of existing PURPA contracts and 3,641 MW of proposed PURPA contracts, together totaling 5,373 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 5,373 MW of existing and proposed PURPA contracts at their nameplate capacity would be enough to supply 79 percent of PacifiCorp's average retail load and 108 percent of PacifiCorp's minimum retail load.[52]

Given this exponential increase in QF contracting activity, it is critical to adjust pricing and contracting procedures quickly once problems with those procedures are identified. The potential financial impact on Idaho customers of this increased QF contract activity is enormous. As noted previously, the Company currently has 189.6 MW of existing PURPA contracts in Idaho and 275.5MW of proposed PURPA contracts in Idaho, together totaling 465.1 MW of nameplate capacity. In addition, the Company has 141 signed PURPA contracts totaling 1,732 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 calculated allocation factors. Idaho's allocated share is typically around six percent.[53]

The expected system-wide revenue requirement over the next ten years from PacifiCorp's executed PURPA contracts is $2.6 billion.[54] In 2015 alone, the projected payment to QFs is $170.5 million, with Idaho's allocated share at $10.2 million.[55] If these projects had been priced

[52] *Id.* at p. 16.
[53] *Id.* at p. 19.
[54] *Id.*
[55] Assuming an allocation factor of six percent. Clements Testimony at p. 20, lines 1-3.

incorrectly by even 10 percent, it would create a $1.0 million impact in 2015 for Idaho customers. That 10 percent impact would grow to a total of $15.4 million over the ten-year period starting in 2015. With a pricing queue that currently totals 3,641 MW, or more than double (in MW size) the $2.6 billion worth of current PURPA contracts to which the Company is already obligated, it is imperative that the indicative pricing provided to prospective PURPA projects be accurate and reflective of the Company's actual projected avoided costs. Failure to implement the modifications proposed by the Company in this docket will result in significant irreversible harm to customers in the form of higher retail rates than what would otherwise occur without the PURPA contracts.[56] This harm will be a direct result of PURPA contracts that, due to their extremely long terms and inaccurate avoided cost assumptions, violate PURPA's ratepayer indifference standard and this Commission's goal of protecting retail customers.

The current Commission-approved PURPA contract length puts retails customers at significant 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. Moreover, the current, Commission-approved avoided cost methodology for management of the pricing queue will distort the Company's indicative avoided-cost calculations for proposed projects that are not first in the queue in a manner that drives costs erroneously upward. If projects ahead of a particular QF in the pricing queue are not considered and included in that QF's indicative avoided cost calculation, that QF may be able to lock in a long-term contract

[56] *Id.* at p. 20.

with pricing that is above the Company's calculated avoided cost.[57] Given the magnitude of new QF requests, this one-way error is becoming progressively more harmful to retail customers.

2. The Commission should permanently reduce the maximum contract term for PURPA contracts from 20 years to three years

The current Commission-approved PURPA contract length puts retails customers at significant risk of harm. Locking in a large and ever expanding volume of power purchases for decades, at fixed prices, creates significant and unnecessary exposure to long-term price risk—a level of risk the Commission would not tolerate 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.[58] Under PURPA, only the Commission can mitigate this price risk to customers.[59]

The Commission recognized this precise risk when it reduced PURPA contract terms from 20 years to five years in the 1996 and 1997 proceedings noted above, finding:

> Significant changes have swept through the electric industry since we last examined the issue of contract length. The FERC has mandated open access to the transmission system, thermal technologies have improved, gas prices are low, there is a considerable surplus of energy available in this region resulting in very low spot market prices for electricity and, finally, even the continued existence of PURPA is being called into question. We find that as the industry as a whole continues to transform to a more free market model, we cannot justify obligating utilities to 20-year contracts for PURPA power. <u>As the utilities in this case note, such an obligation does not reflect the manner in which they are currently acquiring power to meet new load; through short-term (five years or less) purchases. Consequently, 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. We can find no justification for insisting that Idaho's investor-owned utilities and their ratepayers assume such an obligation simply to foster one particular segment of an increasingly competitive industry</u>. We find,

[57] *Id.* at p. 34.
[58] *See id.* at p. 32.
[59] *See id.* at p. 23.

therefore, that Idaho's investor-owned utilities shall not be required to offer contracts to QFs in excess of five years until further action is taken by this Commission. This ruling, however, does not prevent utilities from offering for approval QF contracts with terms that exceed five years should the utilities believe that such contracts are in the best interests of their ratepayers.[60]

Based on this same rationale, the Company asks the Commission to permanently reduce the maximum contract term for PURPA contracts from 20 years to three years, a term which is more aligned with the Company's risk management practices for acquisition of significant utility resources, including the Company's hedging policies and practices and its IRP cycle.[61] This contract reduction would significantly mitigate the price risk to customers caused by mandatory QF power purchases.[62]

(a) The Company requires Commission assistance to mitigate risk related to PURPA contracts

In stark contrast with the Company's essentially unlimited obligation to purchase QF energy, the Company generally procures other long-term resources only after a rigorous review of resource needs, an evaluation of alternative methods of meeting that need, and the selection of the least-cost, least-risk method of meeting its resource needs.

The Company evaluates its long-term planning and resource decisions through the Company's IRP process, which is developed on a two-year cycle with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties.[63] Through that process, the Company determines its long-term resource needs. It does so by evaluating its load growth forecasts in conjunction with its existing resources over a twenty-year

[60] *See* Order Nos. 26576, 27111, 27213; *In re Application of the Washington Water Power Co.*, Case No. WWP-E-97-8, Order No. 27212 (Nov. 1997) (emphasis added).
[61] *See* Clements Testimony at p. 20.
[62] *See* Direct Testimony of Brian P. Dickman at p. 4 ("Dickman Testimony").
[63] Clements Testimony at p. 28.

planning horizon. The Company develops a range of different resource portfolios that could be used to meet its projected resource needs and evaluates the comparative cost and risks of each resource portfolio under a wide range of planning uncertainties. Through this rigorous process, the Company develops a preferred resource portfolio for meeting its resource needs. Once a preferred portfolio is selected, the Company develops an action plan that identifies the steps the Company will take over the next two to four years to implement its resource plan.[64]

Typically, the Company does not enter into long-term transactions unless those transactions have been identified as least-cost, least-risk transactions through the IRP process.[65] Even then, the Company's action plan for acquiring those resources layers in additional risk management and cost management. For example, the Company typically utilizes a rigorous request for proposal ("RFP") process to acquire any long-term resource identified by the IRP action plan. The RFP process is a competitive and transparent process that typically involves extensive input from regulators and objective review of the process by an independent evaluator.[66] This rigorous evaluation process for long-term resources is designed from stem to stern to ensure the Company acquires only the resources the Company needs to serve its customers, and then, in a manner that protects its retail customers.[67]

In stark contrast to the Company's thoughtful, regulated process for acquiring most long-term resources, the Company has limited freedom to actively evaluate or manage PURPA contracts. With the exception of limited terms and conditions the Company may be able to negotiate with larger QFs, QF contracts are simply "put" to the Company, which must accept them in whatever

[64] *Id.*
[65] *Id.*
[66] *Id.* at p. 24.
[67] In addition to the extensive RFP process, any long-term transaction goes through additional analysis and review in conjunction with PacifiCorp's Corporate Governance Policy, which will be described later.

volume, and on whatever terms and conditions, are established by the Commission. PURPA contracts do not go through the same competitive RFP process, with its independent evaluator review, to ensure they are lowest cost and least risk solutions for customers.[68] Nor are PURPA contract executions limited to the size of the resource need identified in the Company's IRP. Finally, PURPA contracts do not receive the same upper management review and analysis as other long-term transactions, because the Company lacks the discretion to refuse the mandatory purchase obligation or the 20-year contract term established by the Commission.[69]

By asking the Commission to revise the terms and conditions of its PURPA contracts to minimize risk to customers, the Company is asking the Commission to step into the Company's shoes to do what the Commission ordinarily asks the Company to do for itself: to ensure that resources procured on behalf of retail customers are as low-cost and as low-risk as possible.

(b) The Company manages hedges carefully to limit customer exposure to potentially harmful and unanticipated swings in power costs; PURPA contracts are essentially unlimited hedges outside the Company's control

When the Company considers purchasing power from a third party, the Company first reviews the proposed purchase from a risk-management perspective. The Commission expects the Company to serve its customers with least-cost, least-risk resources. For that reason, the Company has specific risk-management policies it applies to evaluate any proposed power contracts, to ensure the contracts are reasonable and prudent.[70]

The Company modified its hedging horizon for natural gas and power from 48 months to 36 months as a result of hedging collaborative workshops it held with stakeholders in 2011 and 2012.

[68] Clements Testimony at p. 24.
[69] *Id.*
[70] *Id.* at pp. 20, 32.

The Company's trading policies and procedures are outlined in the PacifiCorp Energy Commercial & Trading Risk Management Policy. That policy 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, SO2 emission allowances, and greenhouse gas allowances.[71] PacifiCorp's commercial & trading organization within PacifiCorp Energy ("Commercial & Trading") 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.[72]

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 Commercial & Trading to engage in trading and risk management activities. Compliance with this policy is mandatory.[73]

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 such expressed interest for electricity hedges beyond 36 months since that time. The Company's risk management metrics are also limited to 36 months.[74]

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

[71] *Id.* at p. 21.
[72] *Id.* at p. 22.
[73] *Id.*
[74] *Id.*

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 lowest 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 size and duration of the transaction, which also increases the level of management approval that is required.[75]

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. Long-term fixed price transactions often move in or out of the money over time as the forward price curve changes.[76]

PacifiCorp's trading and hedging horizon is supported by market and industry evidence. In the unregulated wholesale energy marketplace, very few transactions occur beyond a six-year time horizon, and the highest volume is 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 to serve load, so it contracts to buy the output from a certain generator). Most of these long-term transactions occur through rigorous, transparent, and competitive request for proposals processes.[77]

[75] *Id.* at p. 23.
[76] Clements Testimony at p. 25.
[77] *Id.* at p. 25.

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 – QFs that generally do not need a long-term contract for financing purposes, but can evaluate their available contract options (i.e. term lengths) from a risk-based perspective. Like most utilities, most CHP QFs elect short-term fixed energy contracts—even when 20-year terms are available. In fact, most CHPs QFs elect annual contracts that are renewed each year at the then-current avoided costs. These customers have told PacifiCorp that they are not "energy traders" and therefore prefer to eliminate the price risk that comes from long-term fixed-price contracts.[78]

An example of the price risk associated with a long-term fixed price contract may be useful. 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 wholesale market hub ("Mid-C") was priced at $45.87 per megawatt hour ("MWh"). On February 2, 2015, just six months later, that same ten year contract was priced at $38.11 per MWh. The ten year electricity market moved 17 percent in just six months. Hypothetically, had the Company purchased 100 MW of this ten year fixed price contract on August 1, 2014 at $45.87 per MWh, just six months later the Company would have a mark to market loss of $68.0 million on the contract.[79]

By comparison to this 100 MW ten year example, PacifiCorp currently has 275.5 MW of proposed PURPA contracts in Idaho seeking 20-year fixed price contracts. The price risk associated

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[78] *Id.* at p. 25-26.
[79] *Id.*

with this large number of proposed Idaho PURPA contracts, and their 20-year contract terms, is substantial and should not be borne by customers.[80]

Given the typical contracting and hedging horizons for energy contracts in the utility industry, which are commonly limited to less than 36 months, a 20-year PPA can also be viewed as an inappropriate QF subsidy. As the Company has explained, it is extremely rare for a utility to voluntarily enter into a 20-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 20-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 unusual long-term transaction, or to the QF to account for the price certainty the QF enjoys from such a contract. As this Commission has noted, "avoided cost rates are not the only terms to a PURPA contract."[81] Contract lengths are also PURPA contract terms, and they carry with them their 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 this reason, a guaranteed, fixed-price, 20-year contract at avoided cost is also a QF subsidy—something PURPA was never meant to provide.[82]

This long-term price risk has been evidenced in the Company's existing PURPA contracts. The Company currently has 141 executed PURPA contracts totaling 1,732 MW of nameplate capacity across its six-state system. Idaho's allocated share of these contract costs averages

[80] *Id.*
[81] Order No. 33204 at 8.
[82] Clements Testimony at pp. 11-12.

approximately six percent. Over the next ten years, the Company is under contract to purchase 38.8 million MWhs under its executed PURPA contract obligation at an average price of $66.32 per MWh.[83] The average forward price curve for Mid-C over this same ten years is $38.11 per MWh,[84] or a difference of $28.21 per MWh.[85]

Under PURPA, the Company is not able to apply its internal risk management policies to evaluate the reasonableness and risk profile of PURPA contracts in the same manner it does for non-PURPA contracts.[86] 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. While the Company has some limited ability to negotiate non-standard PURPA contract terms and conditions, and while the Company uses its own 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.[87] In this sense, the Company's primary vehicle for risk management of PURPA contracts is to seek customer-protective policy decisions at the Commission.

By reducing PURPA contract lengths to three years, the Commission will protect customers from undue price risk by introducing a level of risk management control the Company cannot itself impose on PURPA contracts.

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[83] *Id.* at pp. 26-27.
[84] Based on a February 2, 2015 forward price curve for a 7x24 (flat) energy product.
[85] Clements Testimony at p. 27.
[86] *Id.*
[87] *Id.* at p. 21.

3. The Commission should modify the Company's avoided cost methodology as it relates to treatment of proposed QF projects when calculating indicative pricing in order to ensure accurate pricing in contracts in light of recent FERC precedent related to purchase obligations.

The Commission should direct that the preparation of indicative pricing for QFs must reflect all active QF projects in the PacifiCorp pricing queue ahead of any newly proposed QF requests for indicative pricing. This change updates a modeling assumption that, in light of recent FERC precedent, will result in purchase obligations based on indicative pricing provided to QFs, resulting in Commission-approved avoided cost calculations that will not accurately reflect the incremental costs to the Company of energy and capacity unless it is corrected.

The Company reviewed the impact of its large QF pricing queue on avoided costs in Idaho and determined that the currently approved methodology distorts avoided cost pricing due to the requirement that the Company's avoided cost rate modeling can only be updated to account for *signed* QF contracts.[88] This requirement does not recognize the impact of queued QFs that do not yet have a signed contract but are in the process of receiving indicative avoided cost prices and pursuing a power purchase agreement with the Company and, as a result, effectively prices each QF project as if it is first in the queue.[89]

Avoided costs for the first QF in the queue are based on displacement of the highest cost resources on the Company's system.[90] Each successive QF displaces lower and lower cost resources, resulting in lower avoided costs. Further, recognizing additional QFs on the Company's system defers the need to build new resources. Indeed, accumulating several QF

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[88] *See* Dickman Testimony at pp. 3-4.
[89] *See id.*
[90] *See id.* at pp. 2-3.

projects may even completely displace planned thermal resources additions and delay the payment of capacity costs to the next QF in line. If, however, queued QFs are ignored, it will result in payments to QFs that exceed avoided costs if purchase obligations are entered into before indicative pricing can be updated to reflect purchase obligations of other projects in the queue.[91]

FERC has recognized that avoided cost rate imperfections will occur, stating its belief that "in the long run, 'overestimations' and 'underestimations' will balance out."[92] However, ignoring queued QFs is an avoided cost methodology error that results in a one way imperfection – overestimations that will not, in fact, balance out in the long run.[93] This conflicts with FERC's PURPA regulations, which make it clear that an electric utility is under no circumstances required to pay more than avoided cost for QF purchases.[94] By contrast, the same regulations allow state commissions to set a rate for purchases that is *lower* than avoided cost, so long as it is just, reasonable, nondiscriminatory and is sufficient to encourage small power production.[95]

In addition, FERC PURPA regulations governing the rates for QF purchases state that, to the extent practicable, the following shall be taken into account: "[t]he availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including . . . [t]he individual ***and aggregate*** value of energy and capacity from qualifying facilities on the

[91] *Id.* at p. 4.
[92] *See Small Power Production and Cogeneration Facilities – Rates and Exemptions*, Order No. 69, Final Rule Regarding the Implementation of Section 210 of PURPA, 45 Fed. Reg. 12214, at 56-57 (1980).
[93] *See* Dickman Testimony at p. 4.
[94] 18 C.F.R. § 292.304(a)(2).
[95] 18 C.F.R. § 292.304(b)(3).

electric utility's system."[96] This language makes it clear that considering QFs in the aggregate is an important consideration because it may impact the accuracy of avoided cost rates.[97]

Reflecting queued QFs in the determination of avoided cost rates is also consistent with FERC's long-standing interconnection policies – which form the foundation for state jurisdictional QF interconnections – that require interconnection studies to evaluate the impact of a proposed interconnection by considering all generating facilities that, as of the date the study is commenced, have a pending, higher-queued interconnection request to interconnect to the transmission system.[98]

This policy is designed to, among other things, allow for a fair network upgrade cost allocation mechanism. FERC has stated that it would be unfair to require an interconnection customer to sign an interconnection agreement before the interconnection studies identify its requirements for interconnection facilities and network upgrades.[99] To that end, FERC stated, "[w]e recognize that including all the higher queued projects will require a restudy when a higher queued project drops out, but it is essential to include each higher queued project in the study because the Interconnection Studies will be meaningless if higher queued projects are not included."[100]

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[96] 18 C.F.R. § 292.304(e)(2)(vi) (emphasis added).
[97] In its 1980 order implementing these regulations, FERC explained that this provision would allow for QFs to be considered in the aggregate for purposes of allowing a group of QFs to potentially enable a purchasing utility to defer or avoid scheduled capacity additions despite that each QF, if considered individually, would not provide capacity value. *See Small Power Production and Cogeneration Facilities – Rates and Exemptions*, Order No. 69, Final Rule Regarding the Implementation of Section 210 of PURPA, 45 Fed. Reg. 12214, at 54-55, 63, 72 (1980). However, it follows that considering QFs in the aggregate may have other impacts on avoided cost rates as well, and the language of the regulation does not preclude such an interpretation.
[98] FERC *Pro Forma* Large Generator Interconnection Procedures, Section 7.3; FERC *Pro forma* Small Generator System Impact Study Agreement, Section 8.
[99] *See, e.g., Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 161 (2004).
[100] *Id.*

The same rationale applies with regard to reflecting queued QFs in the determination of avoided costs. Just as each successive QF displaces lower and lower cost resources and, thus, results in lower avoided costs and defers the need to build new resources, the network upgrades necessary to accommodate each interconnection customer's interconnection (as determined in the interconnection study) impacts whether and what type of network upgrades may be required to accommodate the interconnection customer next in the queue and, thus, that next interconnection customer's network upgrade cost allocation. If, on the other hand, the higher queued interconnection customers were ignored, the interconnection studies would result in network upgrade cost allocations that exceed what is actually required to interconnect the customer, just as the payments to QFs exceed avoided costs if queued QFs are ignored in the determination of avoided cost rates.

In Case No GNR-E-11-03, the Commission held that avoided costs can only be updated to reflect signed QF contracts,[101] but significant shifts in the PURPA landscape occurring since the time of that holding justify the Commission's reconsideration of this issue. In that same proceeding, Idaho Power proposed that any QF with signed contracts and any queued QFs be included in Idaho Power's resource portfolio for purposes of calculating future avoided costs because they can impact future avoided costs.[102] Idaho Power reasoned that, if queued QFs and QFs with signed contracts are considered part of the resource portfolio, then avoided cost rates for energy and capacity could change for each new QF as a result of the total amount of capacity

[101] *In re Review of PUPA QF Contract Provisions*, Case No. GNR-E-11-03, Order No. 32697 at 22 (Dec. 2012).
[102] For purposes of calculating avoided costs, Idaho Power proposed that a QF would be designated as "queued" upon receipt of a written request from a QF for contract pricing.

and energy provided by all projects in Idaho Power's portfolio – changes that are not captured if the recognition of new long-term commitments is limited to signed contracts.

The Commission adopted Commission Staff's position on this issue – *i.e.*, that only signed QF contracts should be reflected in avoided cost rates – without comment.[103] However, Commission Staff reasoned that "[t]he mere indication of interest or request for a contract is too speculative to justify incorporating a change in the utility's load-resource balance."[104] With regard to Idaho Power's queued QF policy proposal, Commission Staff concluded that "[t]echnically, Idaho Power's avoided costs do not change until a new QF has actually been added to the resource portfolio. A QF that has not signed a contract cannot yet be considered part of the resource portfolio."[105]

Since the time of that proceeding, however, there have been two significant shifts in the PURPA landscape – shifts the Commission Staff could not have anticipated. First, FERC issued a series of orders clarifying that QFs can, under certain circumstances, unilaterally lock in avoided cost rates before the utility signs a contract.[106] Second, there has been a drastic increase in the number of QF requests received by the Company.[107]

With regard to the first shift, historically FERC has stated that it will defer to the states regarding the date on which a LEO is incurred. However, FERC issued four orders in recent years that curtailed state discretion on this issue. All four orders ruled that a state may not

[103] Order No. 32697 at 22.
[104] Case No. GNR-E-11-03, Idaho Public Utilities Commission, Direct Testimony of Rick Sterling, at 24 (May 4, 2012).
[105] *Id.*
[106] Dickman Testimony at p. 9.
[107] *Id.*

require a QF to obtain a fully executed contract as a precondition to obtaining a LEO, with the final order indicating that a LEO may arise even before *any* party signs an agreement.[108]

These FERC orders impact the Commission Staff's original basis for eliminating queued QFs from those that should be reflected in avoided costs. In particular, Commission Staff's conclusion was that the indication of interest or request for a contract was too speculative to justify incorporating a change in the utility's load-resource balance, and that avoided costs do not change until a new QF has actually been added to the resource portfolio, which cannot occur until a QF has signed a contract.[109] However, the recent FERC orders on the establishment of LEOs indicate a QF can unilaterally establish a right to sell to a utility before the contract is signed. Therefore, to ensure customers are protected against an avoided cost rate methodology that results in overestimations that will not balance out in the long run, queued QFs should be reflected in avoided costs.[110]

With regard to the second PURPA landscape shift, there has been a drastic increase in the number of QF requests received in both Idaho and over the Company's six-state system in recent years. Of particular relevance here, more than half of the total PURPA MWs have online dates of 2014 or later, and the Company currently has over 3,500 MW of queued QF capacity.[111] Indeed, if the entire queue is included, rather than just those QFs with signed contracts, avoided costs for the next QF to request pricing fall approximately $18 per MWh on a 20-year levelized basis. Recalculating prices for new QF projects as other queued QFs sign contracts is not a workable solution to this problem, as it would be prohibitively time consuming and problematic

[108] *Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187 (2013); *Murphy Flat Pwr., LLC*, 141 FERC ¶ 61,145 (2012); *Rainbow Ranch Wind, LLC*, 139 FERC ¶ 61,077 (2012); *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 (2011).
[109] *See* Dickman Testimony at pp. 8-9.
[110] *See id.* at pp. 4, 8-10.
[111] *See, e.g.,* Clements Testimony at pp. 3, 14.

from a contract negotiation standpoint. There may be situations where multiple QFs progress toward an executable contract at the same pace and it would be impossible to differentiate which would be entitled to the higher prices that should only apply to the first project to enter into a purchase obligation (the others would require a re-price).[112]

In light of the significant changes in the PURPA landscape that have occurred since the Commission's 2012 ruling, the Commission should modify the Company's avoided cost rate methodology to allow queued QFs to be considered in the calculation of indicative avoided cost pricing in order to prevent artificially inflated avoided cost pricing and harm to retail customers.

IV. CONCLUSION

For the reasons detailed herein, Rocky Mountain Power asks the Commission to issue an order directing the Company to implement the following changes to its PURPA contracting procedures: (1) immediate reduction, on a temporary basis, of the maximum contract term for PURPA contracts between QFs and the Company from 20 years to five years, pending litigation of this case; (2) permanent reduction of the maximum contract term for PURPA contracts from 20 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 IRP cycle; and (3) modification of the Company's avoided cost methodology such that preparation of indicative pricing for QFs that reflects all active QF projects in the pricing queue ahead of any newly proposed QF requests for indicative pricing.

[112] *Id.* at 11.

Respectfully submitted this 27th day of February, 2015.

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