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June 17, 2013

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: UM 1610 – In the Matter of OREGON PUBLIC UTILITY COMMISSION, Investigation into Qualifying Facility Contracting and Pricing

Attention Filing Center:

Enclosed for filing in docket UM 1610 are an original and five copies of Idaho Power Company's Post Hearing Brief.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached certificate of service.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Qualifying Facility Contracting and Pricing.	**IDAHO POWER COMPANY'S POST-HEARING BRIEF**

I. INTRODUCTION

Pursuant to the May 30, 2013, Post-Hearing Memorandum issued by Administrative Law Judges ("ALJ") Traci A. G. Kirkpatrick and Shani Pines, Idaho Power Company ("Idaho Power" or "Company") submits this Post-Hearing Brief to the Public Utility Commission of Oregon ("Commission"). The purpose of this docket is to address various issues related to Oregon's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). This brief addresses only the Phase I issues identified in ALJ Michael Grant's Rulings of December 21, 2012, and January 30, 2013.

Idaho Power's primary recommendations relate to the methods used to determine standard and negotiated avoided cost prices and the eligibility cap for standard avoided cost prices. The Company's recommendations are intended to create a system that more accurately reflects the true avoided costs of a utility to ensure PURPA's strict mandates are satisfied and customers are held indifferent to generation from Qualifying Facilities ("QFs"). Idaho Power's recommendations are also driven by a desire for consistency across its jurisdictions, which will prevent the opportunity for regulatory arbitrage and gaming the system. Idaho Power's proposals are supported by a robust evidentiary record and should be approved.

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II. BACKGROUND

A. Purpose of Docket UM 1610.

The Commission opened this investigation in response to a request made by Idaho Power to change the methodology used to calculate Idaho Power's avoided cost prices available pursuant to standard contracts. Idaho Power's request was the result of several filings made in early 2012—each of which provides important context for the current state of PURPA implementation in Oregon and the Company's recommendations in this case.

On January 27, 2012, Idaho Power filed an *Application to Lower Standard Contract Eligibility Cap*.[1] The Company requested that the Commission reduce the eligibility cap applicable to standard contracts from 10 MW to 100 kW. Idaho Power requested the lower eligibility cap for several reasons, most notably because a lower eligibility cap would require most QF contracts to be individually negotiated, which allows avoided cost prices to be determined based upon each project's specific and unique operating characteristics. Thus, the Company argued that lowering the eligibility cap would ensure that the Commission's implementation of PURPA is consistent with the Federal Energy Regulatory Commission's ("FERC") regulations and would protect Oregon's electric utility customers from bearing excessive costs related to QF generation.

The Company's January 2012 filing reflected an added level of urgency; in the days leading up to the filing Idaho Power received requests for Oregon standard contracts from nine different QFs with a total nameplate capacity of 73 MW. By comparison, in 2011 Idaho Power's average total Oregon customer load was only 87 MW.[2] In addition to the

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[1] The Application was docketed as UM 1575. Concurrent with the Application, Idaho Power also made an advice filing to revise Idaho Power's Schedule 85, which is the Company's PURPA implementation schedule in Oregon, to reflect the requested lowering of the 10 MW eligibility cap. This tariff filing was docketed as UE 244.

[2] Idaho Power/400, Stokes/3.

proposed QF's significant capacity, Idaho Power was also concerned that the avoided cost prices in effect at the time were out-of-date and significantly inflated.

The Commission addressed both filings at a public meeting on February 13, 2012, and in Order No. 12-042, issued on February 14, 2012, the Commission rejected Idaho Power's request to lower the eligibility cap. However, in response to the more immediate concern related to the nine new requests for standard contracts, the Commission temporarily suspended the requirement in Schedule 85 that the Company provide standard contracts to new QFs until the Company updated its avoided cost prices through the integrated resource planning process.[3] Updating the avoided cost prices would reduce the discrepancy between the Company's actual avoided costs and the standard avoided cost pricing reflected in Schedule 85.

Thereafter, on March 15, 2012, Idaho Power made three additional PURPA-related filings: (1) Idaho Power updated its avoided cost prices following the acknowledgment of the Company's 2011 Integrated Resource Plan ("IRP"); (2) Idaho Power filed an *Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices*; and (3) Idaho Power filed a *Motion for a Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities*.[4] The *Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices* requested Commission authorization for Idaho Power to abandon the use of a Surrogate Avoided Resource ("SAR") based methodology in favor of the more accurate and comprehensive IRP-based methodology. The *Motion for a Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities* requested that the Commission extend the Order No. 12-042 temporary suspension of Idaho Power's

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[3] *Re Idaho Power Company Application for Investigation into the Standard Contract Eligibility Cap for QFs,* Docket UM 1575, Order No. 12-042 at 2 (Feb. 14, 2012).

[4] These filings were docketed as UM 1593.

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obligation to enter into standard contracts pending the outcome of the investigation requested by the Company in its *Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices.*

The Commission addressed all three filings at its April 24, 2012, public meeting and issued Order No. 12-146 the next day. The Commission directed Idaho Power to use the same "Standard Method" used by Pacific Power and Portland General Electric Company to calculate prices for their standard contracts during periods of resource sufficiency. The Commission also approved the Company's updated avoided cost prices calculated using the Standard Method. In addition, the Commission lifted the stay that was issued as part of Order No. 12-042 because the Company's avoided cost prices had been updated.

In response to Idaho Power's *Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices*, the Commission "ordered that a generic docket be opened to investigate issues related to electric utilities' purchases from QFs, generally. Idaho Power's requested method for calculating avoided-cost prices will be an issue in the new docket."[5] This docket is the generic investigation opened by the Commission in Order No. 12-146.

B. Idaho Power's Experience Implementing PURPA.

As of December 31, 2012, Idaho Power had 108 PURPA QF projects under contract with an estimated nameplate rating of 829 MW.[6] Of those projects, 103 (779 MW) are currently on-line and an additional 5 projects (50 MW) are scheduled to come on-line between now and 2014.[7] Thus, Idaho Power's contracted PURPA generation represents approximately 45 percent of the Company's 2011 average annual load of 1,858 aMW.[8]

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[5] Order No. 12-146 at 1.

[6] Idaho Power/200, Stokes/5.

[7] Idaho Power/200, Stokes/5.

[8] Idaho Power/200, Stokes/6.

Significantly for this policy docket, Idaho Power's level of QF development far exceeds that of any other Northwest utility—both in terms of nameplate capacity and as a percentage of average load.[9]

Moreover, the QF development on Idaho Power's system is not limited to its Idaho jurisdiction. The Company currently has 18 MW of QF projects in Oregon (compared to only 87 aMW of load).[10] The Company is also close to finalizing additional PURPA contracts for four 10 MW wind projects that, when the projects come online, will increase Idaho Power's Oregon QF nameplate capacity to 58 MW, or 67 percent of the Company's average Oregon load.[11] In addition, the Company received requests in January 2012 for nine standard contracts representing QFs with a total nameplate capacity of 90 MW.[12]

The costs associated with QF development are also substantial. Through December 2012, Idaho Power customers have paid over $1.2 billion for all PURPA projects that have come on-line since 1982.[13] The future cost of the current 108 PURPA projects under contract with Idaho Power is estimated to be an additional $2.8 billion over the remaining life of the contracts for a total historical and estimated future cost of $4.1 billion.[14] In addition, the PURPA-related costs have grown significantly since the conclusion of the Commission's last generic PURPA investigation in UM 1129.[15]

These costs are borne entirely by Idaho Power's customers.[16] Indeed, PURPA related expenses will result in the average residential customer experiencing a rate

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[9] Idaho Power/200, Stokes/6.

[10] Idaho Power/200, Stokes/6.

[11] Idaho Power/400, Stokes/2-3.

[12] Idaho Power/200, Stokes/13.

[13] Idaho Power/200, Stokes/8.

[14] Idaho Power/200, Stokes/8.

[15] Idaho Power/200, Stokes/9-10

[16] Idaho Power/200, Stokes/8-9.

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increase of nearly $100 per year.[17] Large industrial customers will experience rate increases of approximately $138,000 per year and special contract customers may see their rates increase by as much as $3.6 million per year.[18]

III. ARGUMENT

A. The Commission should Modify the Method for Determining Standard Avoided Cost Prices (Issues 1(a), (b) and 4(c).

1. Standard Avoided Cost Prices should Account for the QF's Capacity Contribution.

The Company currently utilizes the Standard Method[19] for determining its standard avoided cost prices. In this case, the Company is recommending only one modification to that method—the separate calculation of the energy and capacity components of the avoided cost price to take into account the specific capacity contributions made by different types of QFs.[20] In particular, the Company's proposed modification would account for the QF's capacity contribution by multiplying the avoided cost of capacity based on a combined cycle combustion turbine plant ("CCCT") by a factor that reflects the QF's contribution to meeting the Company's peak-hour load.[21] Idaho Power recommends that the Commission authorize the Company to utilize the capacity factor values that were recently approved by the Idaho Public Utilities Commission ("IPUC") for use in the Company's Idaho service territory.[22]

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[17] Idaho Power/200, Stokes/11.

[18] Idaho Power/200, Stokes/11.

[19] In Idaho Power's direct testimony (Idaho Power/100), the Standard Method was referred to as the "Oregon Method," which was consistent with past Company filings. However, Staff referred to this methodology as the "Standard Method" in its testimony and therefore in the interests of clarity, the Company now refers to the current methodology as the Standard Method.

[20] Idaho Power/200, Stokes/27.

[21] Idaho Power/200, Stokes/27.

[22] Affidavit of M. Mark Stokes ¶ 4 (May 23, 2013).

Idaho Power's recommendation is reasonable because it utilizes the same methodology as the Company's IRP.[23] As both the Company and Staff recognized, the use of the IRP methodology will result in significantly less controversy when avoided cost prices are updated and is consistent with how other avoided cost price inputs are taken directly from the IRP.[24] For these same reasons, the use of the IRP peak-hour method will also prevent Idaho Power from "gaming" the system.

In addition, the Company's recommended adjustment to the standard avoided cost price is consistent with PURPA's requirement that customers remain indifferent to QF generation and FERC's regulations governing the determination of standard avoided cost prices. FERC requires that standard rates account for the "availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods"[25] to the extent practicable. Section 292.304(c)(3)(ii) of FERC's regulations also specifically states that the standard prices "may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies."[26] Idaho Power's recommendation is consistent with both these regulations.

The Company's proposal is also widely supported by the parties in this case. For example, Staff proposes a substantively similar modification to standard avoided cost prices, although Staff proposes only three resource categories (base load, wind, and solar), rather than the five categories proposed by Idaho Power.[27] In addition, the

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[23] Idaho Power/400, Stokes/19; *see also* PAC/300, Dickman/14-15.

[24] Idaho Power/400, Stokes/19; Staff/200, Bless/4.

[25] 18 CFR § 292.304(e)(2).

[26] *See also Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978,* Order No. 69, 45 Fed. Reg. 12,214 at 12,224 (1980) (18 C.F.R. § 292.304(c)(3)(ii) intended to account for different resource types' contributions to peak loads) (hereinafter "Order No. 69").

[27] Staff/100, Bless/23; Staff/101; Staff/200, Bless/4. Although Staff uses different terminology, Staff points to the same peak-hour values proposed by the Company as the values that would be used under their methodology. *See* Idaho Power Company's 2011 Integrated Resource Plan at 5.

Company's proposal to use the capacity factor values from the IPUC is supported by the Renewable Energy Coalition ("Coalition) and ODOE supports the use of the IPUC values as interim capacity values pending acknowledgment of the Company's next IRP.

Rather than using the Company's proposal to calculate the capacity contribution of a QF, several parties support the use of the Effective Load Carrying Capability ("ELCC") method to account for a QF's capacity contribution.[28] Like the Company's proposal, the use of the ELCC would account for a QF's capacity contribution by reducing the avoided cost of capacity based on a CCCT to reflect a QF resource's specific capacity contribution. Conceptually, the Company agrees that the QF's specific capacity contribution should be taken into consideration when determining the avoided cost prices. However, the Commission should reject the proposed use of the ELCC because, unlike the method used by Idaho Power in its IRP, the ELCC method is a complex, theoretical methodology that does not rely on actual system data.[29]

The Community Renewable Energy Association ("CREA") claims the use of the ELCC method will reduce "gaming" by the utility and reduce the costs incurred by QFs to verify the capacity contribution.[30] CREA's argument is unpersuasive because it is far more difficult for Idaho Power to "game" a method that has been consistently used in the Company's IRPs and is subject to extensive review by stakeholders and the Commission in every IRP filing. In addition, the IRP review process provides a sufficient forum to verify the Company's calculations, just as it provides a sufficient forum to review the numerous other Standard Method inputs taken from the IRP. Indeed, if the Commission approves a new methodology, the ELCC, the risks of gaming and insufficient verification are significantly greater.

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[28] *See e.g.*, CREA Prehearing Legal Brief at 11; RNP Prehearing Memorandum at 2.

[29] PAC/300, Dickman/14-15.

[30] CREA/400, Hilderbrand/6.

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2. Idaho Power's Standard Avoided Cost Prices should not Account for Avoided Transmission.

Several parties propose additional adjustments to standard avoided cost prices to reflect the avoided costs of transmission associated with the QF transaction.[31] This adjustment is unnecessary for Idaho Power because all parties in this case have assumed that the theoretical CCCT proxy unit would be in Idaho Power's service territory and therefore Idaho Power would not avoid any transmission expenses associated with an off-system proxy resource.[32]

However, if the Commission decides to account for the avoidance of these transmission expenses, the Commission must also account for *additional* transmission expenses that may be incurred.[33] QF energy is frequently surplus and therefore must be sold into the market. To facilitate these sales, Idaho Power incurs a transmission cost to move the surplus energy to market and other transactional costs.[34] These transmission and transactional costs are not currently accounted for in the standard avoided cost calculations.[35]

3. Standard Avoided Cost Prices should not be Adjusted to Account for Avoided Gas Infrastructure Investments.

CREA and OneEnergy propose an adjustment to standard avoided cost prices to account for increased investment in natural gas infrastructure that would be required to serve the proxy gas plant.[36] This proposal should be rejected. Implementing the CREA and OneEnergy proposal would require detailed assumptions regarding the geographic

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[31] *See, e.g.* OneEnergy/100, Eddie/22, .

[32] *See* Idaho Power/400, Stokes/25; CREA/200, Reading/18.

[33] Idaho Power/200, Stokes/17.

[34] Idaho Power/400, Stokes/25-26.

[35] Idaho Power/400, Stokes/25-26.

[36] OneEnergy/100, Eddie/22; CREA/200, Reading/23.

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location of the proxy resource that are currently not included in the Company's IRPs.[37] Developing and justifying these geographic assumptions will prove to be a lengthy and contentious process.[38] *Second,* the calculation required to implement the adjustment will likely result in a minimal cost adjustment.[39]

4. Additional Upward Adjustments for Deferred Capacity are Unwarranted.

CREA and OneEnergy also propose an additional adjustment to account for deferred capacity investments resulting from the QF transactions.[40] This proposal should be rejected because QFs already receive a capacity credit during a utility's resource deficiency period and there is therefore is no need to provide another payment related to avoided capacity.[41] In addition, the market prices used to determine the avoided cost price during the sufficiency period are firm prices that "embed[] the value of incremental QF capacity in the total market-based avoided cost rate."[42]

Moreover, from a practical standpoint, the addition of unplanned, small QFs does not result in the deferral of new, near-term resources because utilities do not have control over the addition of small amounts of QF capacity and are not able to plan for these additions in the IRP process.[43]

CREA and OneEnergy rely on a study from the United States Department of Energy ("USDOE") on the benefits of distributed generation to support their argument that the

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[37] Idaho Power/400, Stokes/27.

[38] *In the Matter of Public Utility Commission Investigation Into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 25 (Jan. 8, 2007) (IRP process examines generic, not specific resources, to "keep the IRP process separate from the procurement process").

[39] Idaho Power/400, Stokes/27.

[40] OneEnergy/100, Eddie/10; CREA/200, Reading/25.

[41] Idaho Power/400, Stokes/26.

[42] *Re Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 05-584 at 28 (May 13, 2005).

[43] Idaho Power/200, Stokes/13-14; Idaho Power/400, Stokes/26.

addition of small distributed generation allows a utility to defer large generation investments.[44] That study, however, applies "to energy systems that produce electricity . . . at or near the point of use . . . [which] are typically situated within or near homes, buildings or industrial plants . . ."[45] The types of QFs that are transacting with Idaho Power do not fit this description and therefore the underlying premise of the study does not support an adjustment to the Company's avoided cost prices.[46]

CREA and OneEnergy also rely on a PacifiCorp study related to demand side management ("DSM"), which CREA and OneEnergy claim can be used to approximate the value of the capacity they claim is deferred.[47] However, the comparison of QFs to DSM programs is inapt. Unlike QF development, DSM can be reasonably forecast in the IRP process and DSM programs are under the control of the utility and can be managed so they delay the need for new utility resources in the near term.[48] In addition, the PacifiCorp study was not designed to approximate an avoided cost price. Rather, the PacifiCorp study was used to determine the cost effectiveness of DSM resources.[49] Thus, the PacifiCorp study does not support the avoided cost price adjustment proposed by CREA and OneEnergy.

5. Small Distributed Generation QFs should Receive no Special Treatment.

One Energy proposes special treatment (*e.g.*, access to levelized prices, longer contract terms, higher standard avoided cost prices) for QFs that are less than 3 MW and interconnect directly to the utility's distribution system.[50] However, OneEnergy has failed

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[44] OneEnergy/100, Eddie/10; CREA/200, Reading/15, 26.

[45] Idaho Power/400, Stokes/37.

[46] Idaho Power/400, Stokes/36-37.

[47] OneEnergy/100, Eddie/12-14; CREA/200, Reading/27.

[48] Idaho Power/400, Stokes/26; PAC/300, Dickman/36.

[49] PAC/300, Dickman/36.

[50] OneEnergy/100, Eddie/6.

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to present persuasive evidence to support its proposed avoided cost adder for small QFs and even admits that the QF proposals in this case (presumably including this one) "have not been adequately studied."[51] In Order No. 05-584 the Commission addressed a party's similar proposal for an increased avoided cost rate for QFs under 3 MW "to compensate this class of QFs for the additional costs that utilities and ratepayers avoid through the benefits conferred by small QFs generation."[52] The Commission rejected the request, concluding that the record failed to demonstrate how the alleged benefits actually resulted in costs that a utility incurs in the absence of the QF generation.[53] Here, the Commission should also reject this proposal and affirm that all QFs eligible for standard avoided cost prices and contracts receive the same contracts and standard avoided cost prices calculated using a uniform methodology.[54]

6. Standard Avoided Cost Prices should not Unreasonably Encourage Renewable Development at Customer's Expense.

CREA argues the Commission "should do everything in its power to *encourage* QF development because federal and state law mandates that it do so."[55] While it is true that PURPA was intended to encourage the development of alternative generation resources, the Commission cannot inflate the avoided cost price to do so. Section 292.304(2) of FERC's regulations, codified as 18 C.F.R. § 292.304(2), states unequivocally that "[n]othing in this subpart requires any electric utility to pay more than the avoided costs for purchases." As FERC explained:

> PURPA requires an electric utility to purchase power from a QF, but only if the QF sells at a price no higher than the cost

[51] OneEnergy's Prehearing Issues Brief at 15.

[52] Order No. 05-584 at 30.

[53] *Id.* at 31.

[54] Idaho Power/400, Stokes/27-28.

[55] CREA's Prehearing Legal Brief at 3.

> the utility would have incurred for the power if it had not purchased the QF's energy and/or capacity, i.e. would have generated itself or purchased from another source.[56]

When FERC's rules were challenged, the United States Supreme Court upheld the rules concluding that PURPA "sets full avoided cost as the *maximum* rate that [FERC] may prescribe."[57]

Specifically with respect to renewable development, FERC has been clear that the Commission cannot set an avoided cost price that includes a "bonus" or "adder" intended to encourage renewable development.[58] FERC observed that states have "numerous ways outside of PURPA to encourage renewable resources," but inflating the avoided cost price is not one of them.[59]

The Commission has also consistently rejected requests to adopt improper adders that are not reflective of the actual costs a utility avoids.[60] In Order No. 84-742 the Commission specifically rejected the argument that higher avoided cost prices were necessary to encourage renewable development.[61] The Commission recognized that lower avoided cost prices would reduce QF development but reasoned that this result was acceptable because "[i]n periods of surplus . . . fewer projects are needed."[62] The Commission continued that "[w]hen deficits are projected, avoided costs will rise and opportunities for profitable facility development will expand."[63]

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[56] *So. Calif. Edison. Co.*, 71 F.E.R.C. P 61,269, 62,079 (F.E.R.C. 1995).

[57] *American Paper Institute, Inc. v. American Elec. Power Service Corp.*, 461 U.S. 402, 413 (1983).

[58] *So. Calif. Edison Co.*, 71 F.E.R.C. at 62,080.

[59] *Id.*

[60] Order No. 05-584 at 30-31.

[61] *Re Proposed Amendments to Rules Relating to Cogeneration and Small Power Production Facilities*, Docket AR 102, Order No. 84-742 at 3 (Sept. 24, 1984).

[62] *Id.*

[63] *Id.*

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7. The Commission should Reject Requests for Levelized Pricing.

Idaho Power also recommends that the Commission reject requests that would allow a QF to obtain levelized rates.[64] In effect, levelized pricing represents a loan from Idaho Power's customers to the QF in the early years of the contract (when the contract rate exceeds avoided costs) with the expectation that the QF project will pay back the customer loan in the back half of the contract (when the contract price is less than avoided costs).[65] With this loan comes risk and potential customer harm. For example, Idaho Power was recently forced to litigate when a QF with a levelized contract defaulted.[66] The end result, was that the Company was unable to recover the full overpayment that resulted from the levelized pricing—despite the fact the contract included liquidated damages and other customer protections,.[67] Another risk associated with levelized pricing involves the degradation in energy generation over the life of a contract, which can result in an overpayment in the early years of a contract that is never repaid in the later years.[68]

Finally, based on Idaho Power's experience, levelized pricing is unnecessary for QF development. Indeed, despite the fact that levelized pricing is available in Idaho, only 5 of 51 contracts executed in the last 13 years have sought levelized prices.[69] In addition, interest in standard contracts continues in Oregon even in the absence of levelized pricing.[70]

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[64] Idaho Power/200, Stokes/74.

[65] Idaho Power/200, Stokes/75.

[66] Idaho Power/200, Stokes/75-76.

[67] Idaho Power/200, Stokes/75-76.

[68] Idaho Power/200, Stokes/76.

[69] Idaho Power/200, Stokes/76-77; Idaho Power/400, Stokes/23-24.

[70] Idaho Power/400, Stokes/23-24.

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B. The Commission should Authorize Idaho Power to use the Incremental Cost IRP Methodology for Negotiated Avoided Cost Prices (Issues 1(a) and 4(c)).

For negotiated QF contracts, Idaho Power's Schedule 85 states that the "starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW."[71] The IPUC recently authorized Idaho Power to use the "incremental cost IRP methodology" as the starting point for negotiated contracts.[72] The IPUC concluded that the incremental cost IRP methodology was reasonable because it focuses on "incremental costs, not solely on the value of potential market sales."[73] The IPUC found that the incremental cost IRP methodology results in a "more accurate avoided cost . . . [that] comports with the definition of avoided cost contained in FERC regulations."[74] Accordingly, Idaho Power recommends that Schedule 85 continue to incorporate the IPUC-approved methodology, and therefore allow Idaho Power to utilize the incremental cost IRP methodology as the starting point for negotiated contracts.

The original IRP-based methodology, which the Company used in Idaho and continues to use in Oregon pending the outcome of this case, utilized two power cost model runs, one with the QF and one without, to determine the avoided cost of energy.[75] In both runs, the load and operation of Idaho Power's resources was static, so the QF's energy either displaced a market purchase or supplied a market sale.[76] Thus, under the

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[71] Schedule 85-8.

[72] Idaho Power/200, Stokes/30. The incremental cost IRP methodology is described in detail in the Company's testimony and in the Company's Pre-Hearing Memorandum. Idaho Power/200, Stokes/33-34; Idaho Power Company's Pre-Hearing Memorandum at 7-8.

[73] *Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) Methodologies For Calculating Avoided Cost Rates,* Case No. GNR-E-11-03, Order No. 32697 at 21 (Dec. 18, 2012).

[74] *Id.*

[75] Idaho Power/200, Stokes/34.

[76] Idaho Power/200, Stokes/34.

former methodology, the QF generation is essentially valued at the power cost model's estimate of future market prices[77] and results in customers assuming an inordinate market risk that they would not have absent the QF transaction.[78]

The incremental cost IRP cost methodology does not suffer from this flaw. The incremental cost IRP methodology values the QF generation at the highest displaceable incremental cost Idaho Power is incurring during the hour and does not assume that the QF generation supports surplus sales. Therefore, the incremental cost IRP methodology does not result in the shifting of market risk onto customers.

Idaho Power's incremental cost IRP methodology also better embodies FERC's definition of "avoided cost." "Avoided costs" are 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.[79] Under the incremental IRP methodology, the *incremental costs that Idaho Power would have incurred but for the QF generation* is the basis for QF contract pricing.[80] In both the former implementation of the IRP methodology and the incremental cost IRP methodology, QF generation is used to displace purchases. When purchases are displaced, the QF generation is valued at the cost of the displaced purchase. However, in the incremental cost IRP methodology, if the QF generation is not used to displace a purchase (a cost that Idaho Power would have incurred, but for the QF generation), it is used to displace one of Idaho Power's thermal resources (another cost that Idaho Power would have incurred but for the QF generation).[81]

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[77] Idaho Power/200, Stokes/35.

[78] Idaho Power/200, Stokes/30.

[79] 18 C.F.R. § 292.101(b)(6).

[80] Idaho Power/200, Stokes 34.

[81] Idaho Power/200, Stokes 34.

CREA and ODOE are critical of the incremental cost IRP methodology because it does not consider the value of potential wholesale power sales.[82] This criticism is unpersuasive. FERC's definition of "avoided cost" makes no reference to valuing QF energy based on off-system sales. Indeed, in Order No. 69 FERC observed:

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by the qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. **These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.**[83]

The Commission has also recognized that avoided cost prices do not account for the value of off-system sales:

> An avoided cost standard ignores a utility's ability to sell power in the wholesale market at higher rates. Because, when the utility has excess generating capacity, avoided costs measure only the utility's cost to generate additional electricity . . . the avoided costs standard fails to capture any increased value of that excess capacity if sold on the market.[84]

Even ODOE witness Philip Carver testified in a previous Commission proceeding, UM 1559, that the value of off-system sales represents an *opportunity*, and not an

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[82] *See e.g.* ODOE/100, Carver/7; CREA/200, Reading/5; CREA's Prehearing Legal Brief at 4. CREA's brief also claims Staff agrees with CREA on this point. However, CREA cites to Staff/200, Bless/12, which states that Staff supports generally CREA's points made on CREA/200, Reading/6. However, nowhere on CREA/200, Reading/6, does Dr. Reading discuss the value of off-system sales. That discussion occurs on a different page of his testimony (CREA/200, Reading/5) and therefore, CREA's statement that Staff "agree[s] with CREA on this point" is incorrect.

[83] Order No. 69 at 12,219; *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688 ¶ 24 (2006) (utilities not obligated to pay for QF energy that is not needed).

[84] *Wah Chang v. PacifiCorp*, Docket UM 1002, Order No. 09-343 at 33 (Sept. 2, 2009);

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avoided, cost.[85] Dr. Carver's testimony, filed on behalf of Commission Staff, made clear that the opportunity cost, *i.e.*, the value of off-system sales, is "beyond PURPA avoided costs."[86]

Dr. Carver's testimony in UM 1559 is consistent with Commission precedent. In Order No. 84-720 the Commission concluded that an "opportunity cost is neither a generation cost nor a purchase cost under the terms of [PURPA's] statutes, rules, or regulations."[87] Therefore, "proxy prices and opportunity costs are foreign concepts to the clear statutory language" defining avoided costs.[88]

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[85] Idaho Power/501 at 1 ("If a utility is buying power in that hour, the price is the avoided costs. If the utility is selling, the price is the opportunity cost of the wholesale sales made available by the production of the solar photovoltaic power."); *see also Re Portland General Electric Company*, Docket UE 125, Order No. 01-489 (June 15, 2001) ("the opportunity cost (i.e., market value)").

[86] Idaho Power/500 at 7 ("To get a fair measure of the value the Commission should consider other elements beyond PURPA avoided costs. Opportunity cost is one value the Commission should include in solar resource value."); Idaho Power/500 at 12 ("As long as the concept of opportunity cost is retained, there is nothing wrong with borrowing parts of the PURPA approach for solar resource value.").

[87] *Re Investigation of Avoided Costs and of Cost-Effective Fuel Use and Resource Development*, Docket UM 21, Order No. 84-720, 62 P.U.R.4th 397, 412 (Sept. 12, 1984) (emphasis in original). The Commission affirmed this analysis the following year. *Re Adoption of Administrative Rules Relating to Cost-Effective Fuel Use and Resource Development*, Docket AR 112, Order No. 85-010 at 7 (Jan. 8, 1985) ("The [avoided cost definition in ORS 758.505] precludes allowances for prospective electricity sales for resale . . ."). The use of market prices for purposes of determining the standard avoided cost price when utilities are resource sufficient is consistent with the Commission's previous legal conclusions that the avoided cost price should not account for potential off-system sales. When the Commission adopted the current Standard Method in Order No. 05-584, the use of market prices during the sufficiency period was based on the conclusion that the QF generation would offset utility market purchases during the sufficiency period—not on the conclusion that QF generation would support market sales during the sufficiency period. Order No. 05-584 at 28.

[88] Order No. 84-720, 62 P.U.R.4th 397, 412 ("'Avoided cost' means the incremental cost to an electric utility of electric energy or energy and capacity that the utility would **generate** itself or **purchase** from another source but for the purchase from a qualifying facility." Proxy prices and opportunity costs are foreign concepts to the clear statutory language. These concepts also violate the policy scheme underlying the law. ORS 758.505, et seq., is designed to benefit the QF, only to the extent rates to electric consumers remain at or below what they would have been otherwise. Without using purchases or generation, there can be no assurance that prices paid to QFs would not exceed the cost of alternative resources.") (emphasis in original).

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CREA is also critical of Idaho Power's proposal because CREA claims that it treats QFs different from utility-owned resources. CREA argues that the incremental cost IRP methodology "pretends that, unlike utility-owned plants, QF output cannot support off-system sales and thereby 'ignores the full value of QFs contribution.'"[89] Indeed, CREA's own witness, Dr. Reading, admitted in a proceeding before the IPUC that QFs do not want the same treatment as regulated utilities and therefore claims of unequal treatment as a basis for inflating the avoided cost price are without merit.[90]

C. Idaho Power should Receive a Portion of the Renewable Energy Certificates ("RECs")Generated by QFs (Issue 2(c)).

Idaho Power recommends that the Commission revise OAR 860-022-0075 so that *for negotiated contracts* half of the RECs associated with the QF energy are owned by the purchasing utility. For standard contracts, Idaho Power proposes no change to the Commission's rule. Idaho Power's recommendation is intended to align Idaho and Oregon, consistent with the Company's approach to most of the issues presented in this case.[91]

The policies underlying PURPA support the ownership of the RECs by the utility. PURPA compels utilities to purchase energy and capacity from generators that are fueled by specific resources, such as biomass, solar, wind, waste, and geothermal, or in specific configurations, such as cogeneration. If those generators were not powered by those specific resources, several of which are renewable, utilities would not be required to purchase that energy under PURPA. In other words, for certain QFs, the utility is required to purchase the output of these types of generators *because of their environmental*

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[89] CREA's Prehearing Legal Brief at 4.

[90] Idaho Power/502 at 224.

[91] *See Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) Methodologies For Calculating Avoided Cost Rates,* Case No. GNR-E-11-03, Order No. 32802 (May 6, 2013).

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attributes.[92] Therefore, it is reasonable that half of the RECs are owned by the purchasing utility under a negotiated contract.[93]

D. Avoided Cost Prices should be Updated Annually (Issue 3).

To maintain consistency with its Idaho jurisdiction, Idaho Power proposes that standard rates be updated annually using the natural gas forecast published by the United States Energy Information Administration ("EIA").[94] The update would occur in conjunction with the release of the EIA forecast. With respect to the incremental IRP methodology, Idaho Power proposes an annual update of the gas price forecast and load forecast.[95]

E. Both Standard and Negotiated Contracts should Account for Wind Integration Expenses (Issue 4(a)).

1. The Standard Contract Should Provide for an Integration Charge.

Idaho Power recommends that the Commission authorize Idaho Power to charge the cost of wind integration to wind QF projects at a level commensurate with the results of the Company's most recent wind integration study.[96] Transactions with wind QFs result in higher costs to customers because Idaho Power is required to provide additional operating reserves from dispatchable resources capable of increasing or decreasing generation on short notice to offset changes in wind generation.[97] Holding additional operating reserves on other dispatchable resources means that the operation of those resources is restricted and they cannot be economically dispatched to their fullest capability.[98] If Idaho Power's

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[92] Idaho Power/200, Stokes/78-79.

[93] It is possible for the parties to a negotiated QF contract to agree to a different disposition. However, the Company's proposal is intended to establish a default allocation of RECs in the absence of an agreement to the contrary.

[94] Idaho Power/200, Stokes/67.

[95] Idaho Power/200, Stokes/67.

[96] Idaho Power/200, Stokes/67-73.

[97] Idaho Power/200, Stokes/67-68.

[98] Idaho Power/200, Stokes/67-68.

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customers are responsible for paying for the costs to integrate wind QFs, then customers will be harmed in violation of PURPA.[99] Moreover, this customer harm can no longer be ignored because of the substantial wind development on Idaho Power's system, which causes significant integration costs.[100]

The imposition of a wind integration charge is widely supported by the parties to this case.[101] While the parties do not necessarily agree on the specific level of the integration charges or the process by which integration studies should be updated, conceptually these parties recognize that wind QFs impose costs on utility customers that would not be imposed in the absence of the QF transaction. Therefore, it is appropriate for QFs to pay for those costs, either through a reduction in the avoided cost price or through a separate contract provision.

CREA argues that QFs should not pay integration charges because wind projects "should be dispersed geographically on the utility's system" and that small QFs provide benefits to the utility's system that balance out the integration costs.[102] These arguments are unpersuasive. *First*, the Company's wind integration study accounted for the actual and expected geographical dispersion of QFs wind projects and nevertheless supports the imposition of an integration charge.[103]

Second, CREA relies on an inapplicable USDOE distributed generation study to argue that the benefits of distributed wind generation offset integration costs.[104] A majority

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[99] *So. Cal. Ed. Co.*, 71 F.E.R.C. at P 62,079.

[100] Idaho Power/200, Stokes/52; *see also* Order No. 07-360 at 24-25 (integration costs increase as the level of wind penetration increases).

[101] *See e.g.,* RNP Prehearing Memorandum at 3; Staff's Prehearing Memorandum at 10; ODOE's UM 1610 Pre-Hearing Memorandum at 7; OneEnergy's Prehearing Issues Brief at 9; Coalition Prehearing Memorandum at 10.

[102] CREA/200, Reading/15.

[103] Idaho Power/400, Stokes/35.

[104] Idaho Power/400, Stokes/36-37.

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of the benefits identified in the USDOE study on distributed generation are provided by generation resources that can be dispatched or are capable of operating at a high capacity factor and provide the type of system benefits that are not associated with wind. Indeed, the study itself does not identify wind resources as the type of resource that provides the benefits CREA claims offset integration charges.[105]

2. The Wind Integration Charge should be Established Using Idaho Power's Most Recent Wind Integration Study

Idaho Power's wind integration study provides robust evidentiary support for Idaho Power's proposed wind integration charge[106] and represents the most recent integration cost data available.[107] To determine the level of wind integration costs, Idaho Power's study isolates the effects of wind on the operation of the dispatchable resources by looking at two scenarios.[108] *First*, the study models the operation of dispatchable resources when they are burdened with incremental balancing reserves required by wind generation. *Second*, the study runs the same model without the additional balancing reserves. The study's general methodology is consistent with the Company's previous studies and simply reflects refinements that have resulted in a more accurate assessment of the costs of integration.[109]

Parties are critical of Idaho Power's integration study because the study did not specifically study QFs.[110] However, Idaho Power's study does include Idaho Power's QFs.

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[105] Idaho Power/400, Stokes/36-37. CREA also relies on study from Northwestern Energy to support its claim that small, dispersed QFs provide system benefits and lower integration costs. However, like the USDOE study, the Northwestern Energy study is inapplicable here. PAC/300, Dickman/30.

[106] Idaho Power/205.

[107] *See* Order No. 07-360 at 24 ("the utility should use the most recent integration cost data available").

[108] Idaho Power/400, Stokes/29. The full wind integration study is Idaho Power/205.

[109] Idaho Power/400, Stokes/29-30.

[110] RNP/100, Lindsay/10.

Indeed, the study examined the costs associated with Idaho Power's entire wind fleet, which as of January 2013 consisted of 577 MW of wind QFs and a single, 101 MW non-QF resource.[111]

RNP also criticized the Company's study for using synthetic, rather than actual, wind data.[112] However, the data used by Idaho Power was developed by a reputable independent consultant and is representative of the geographic dispersion of wind build-outs Idaho Power is currently integrating and likely to integrate in the future.[113] Although the majority of Idaho Power's wind fleet is centered on the Snake River plateau, the 43 locations that were included in Idaho Power' study are spread across a wide region, with locations in five states—Oregon, Idaho, Utah, Wyoming, and Montana.[114]

RNP also criticized the Company's study for determining its balancing reserves based on day-ahead, rather than hour-ahead, scheduling.[115] Idaho Power's method is reasonable, however, because all deviations between forecast and actual wind production need to be covered—both day-ahead and hour-ahead.[116] Thus, if the Company determined its balancing reserves based on only hour-ahead deviations, the Company's dispatchable generators would be scheduled to carry a *smaller* amount of reserves to cover only deviations as determined from analysis of *hour-ahead* forecast errors.[117] The dispatchable generators would not be scheduled to allow them to respond to day-ahead forecast errors, meaning that the response to these *larger* errors is only achieved by some other means, which in Idaho Power's view would too often translate to a risky reliance on

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[111] Idaho Power/400, Stokes/28-29.

[112] RNP/100, Lindsay/15.

[113] Idaho Power/400, Stokes/34-35.

[114] Idaho Power/400, Stokes/34-35.

[115] RNP/100, Lindsay/14.

[116] Idaho Power/400, Stokes/33-34.

[117] Idaho Power/400, Stokes/33-34.

the wholesale electric market.[118] Consequently, the prudent simulation of day-ahead system scheduling is necessary to ensure that dispatchable generators are capable of responding in real-time to uncertainty in wind production as determined by analysis of day-ahead forecast errors.[119]

F. The Standard Contract Eligibility Cap should be Lowered to 100 kW for Wind and Solar QFs (Issue 5(a) and (c)).

1. Lowering the Eligibility Cap Will Result in a More Accurate Avoided Cost.

If the eligibility cap is lowered, more QF contracts will be negotiated, which results in a more accurate avoided cost price. Both FERC and the Commission have recognized that standard avoided cost prices are an approximation of a utility's actual avoided costs because the standard price does not take into account the QF's specific project characteristics.[120] Lowering the eligibility cap for wind and solar QFs will ensure that the avoided cost rate paid by customers is specifically tailored to these QF's unique operational characteristics because the rate will specifically consider the individual QF's availability, dispatchability, reliability, and the usefulness of the QFs energy and capacity during system emergencies.[121] Staff specifically acknowledges this benefit of IRP-based modeling explaining that such methods "account for a greater array of costs associated with the purchase of QF power" including the QF's "specific operating characteristics [and] . . . the hourly variations in the QFs expected generation and in the utility's load [and] . . . inherently factor in the different operating characteristics of wind, solar and other QF types."[122]

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[118] Idaho Power/400, Stokes/33-34.

[119] Idaho Power/400, Stokes/33-34.

[120] *See* Order No. 05-584 at 16; Order No. 69 at 12,223.

[121] Idaho Power/200, Stokes/53-54; 18 C.F.R. § 292.304(c)(3)(ii) and (e).

[122] Staff/100, Bless/13.

In addition, negotiated rates based on the Company's incremental cost IRP methodology are less sensitive to gas price volatility, which has historically been the most volatile of all the inputs used to set avoided cost rates.[123] Thus, using a methodology that is less sensitive to the gas price forecast will likewise reduce the volatility of avoided cost rates.[124]

Despite these advantages, many parties are critical of the incremental cost IRP methodology, as compared to the Standard Method, arguing that it is a more complex and less transparent methodology.[125] This criticism ignores the fact that the basis for the incremental cost IRP methodology is the Company's acknowledged IRP, which is acknowledged only after extensive public process and approval by the Commission.[126] Staff recognized that these "models are well established and in fact are the same models that are used to prepare the Integrated Resource Plan."[127]

Moreover, in the process of negotiating a contract, Idaho Power will provide the QF project with proposed indicative avoided cost values in accordance with Schedule 85 and respond to QF questions with regard to the price modeling.[128] If these questions require review of model runs, input data, etc., Idaho Power will provide this data in a reasonable manner in compliance with any applicable confidentiality and software licensing requirements.[129]

Even the Coalition recognized that "[w]hile the integrated resource method may not be as transparent as the surrogate resource method, it can do a better job of taking into

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[123] Idaho Power/400, Stokes/9-11.

[124] Idaho Power/400, Stokes/11.

[125] *See e.g.* ODOE/100, Carver/5-6.

[126] Idaho Power/400, Stokes/12.

[127] Staff/100, Bless/13.

[128] Idaho Power/400, Stokes/12.

[129] Idaho Power/400, Stokes/12.

account a utility's needs by incorporating all the expected loads and resources . . ."[130] Thus, the incremental cost IRP methodology will result in a more accurate avoided cost price.

2. Market Barriers No Longer Necessitate a 10 MW Eligibility Cap.

a. QF Developers are Highly Sophisticated.

Idaho Power's experience has shown that as a group, QF developers are highly sophisticated, have access to contract experts, possess sufficient financial resources to negotiate a PURPA contract, and are willing and able to disaggregate large projects specifically to obtain standard rates.[131] For example, Idaho Power has standard contracts for 19 different wind QFs developed by Exergy Development Group, which has developed over 4,000 MW of wind in the United States.[132] Idaho Power also has QFs developed by subsidiaries of John Deere and projects that are owned by Shell Oil.[133] Indeed, of the 27 total wind QFs currently either online or under contract with Idaho Power, only one QF, developed by Joseph Millworks, Inc., was not developed by a sophisticated renewable energy development company with years of experience developing renewable projects.[134] And that one QF has a total capacity of 3 MW, or approximately 0.4 percent of Idaho Power's total QF wind capacity.[135] These developers clearly have both the sophistication and the financial resources to negotiate a contract with Idaho Power.[136]

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[130] Coalition/200, Schoenbeck/9.

[131] *See also* PAC/200, Griswold/19 ("the Company is now negotiating with well-funded, experienced developers who have successfully developed multiple QF and renewable projects across the country, and hire some of the most skilled technical and legal firms in the country.").

[132] Idaho Power/200, Stokes/59-60. Exergy's QFs have a total nameplate capacity of 321.72 MW. Eleven of these projects were developed together at a cost of $500 million as part of "Idaho's largest wind power project."

[133] Idaho Power/200, Stokes/60.

[134] Idaho Power/200, Stokes/61.

[135] Idaho Power/200, Stokes/61.

[136] Idaho Power/200, Stokes/61-62.

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The Commission's rationale for adopting a 10 MW eligibility cap was to "eliminate negotiations for QF projects for which they would be *economically prohibitive*."[137] For these developers, who are overwhelmingly the developers of wind QFs in Idaho Power's service territory, negotiating an individualized PURPA contract is well within their means.

CREA's testimony claims that community renewable projects, defined as "projects of 20 MW or less that have substantial local ownership," lack the means to negotiate a PURPA contract with a utility.[138] However, CREA admits that a 10 MW wind project costs $20 to $25 million to construct[139] and that the owners typically invest $5 to $7 million equity in the project.[140] CREA also recognizes that even small-scale projects already engage in sophisticated engineering analysis, land leases, engage legal counsel for financing and corporate development, conduct detailed wind resource analysis, retain experts to conduct historical, cultural, and environmental studies, and address transmission and interconnection issues.[141] Indeed, CREA testified that the legal fees related to financing can exceed $350,000.[142] It is not credible for CREA to argue that small-scale developers that are engaged in this level of sophisticated project development for a $25 million project lack the resources or sophistication to negotiate a PURPA contract.

Moreover, even CREA's own testimony confirms that community renewable projects are atypical and not necessarily representative of the types of QFs that are contracting

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[137] Order No. 05-584 at 40 (emphasis added).

[138] CREA/100, Hilderbrand/4-5, 11-12.

[139] CREA/100, Hilderbrand/4; CREA/Hilderbrand/3. PGE's testimony confirmed that a 10 MW QF project has an estimated capital cost of $21.3 million.

[140] CREA/400, Hilderbrand/3.

[141] CREA/100, Hilderbrand/12-13.

[142] CREA/100, Hilderbrand/13.

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with Idaho Power. CREA could identify only three community renewable projects in Oregon and Washington,[143] as compared with Idaho Power's 27 wind QF contracts.

In addition, in Idaho Power's experience it is unusual for one developer to construct one QF as an individual, isolated development. Indeed, all but three of Idaho Power's wind QFs were constructed by a developer that was also more or less simultaneously developing several other QFs.[144] For example, in the near future Idaho Power anticipates finalizing standard contracts for four 10 MW wind projects in Oregon.[145] These projects are being developed simultaneously by the same entity.[146] Therefore, when examining the developments costs for these projects (or similar projects) it is reasonable to examine the costs to develop one 40 MW project because for negotiation purposes that is what would occur.

b. The Commission's Negotiation Guidelines Mitigate Other Market Barriers.

In Order No. 05-584 the Commission concluded that for QFs greater than 10 MW market barriers could be sufficiently mitigated through the adoption of the large QF guidelines in Order No. 07-360.[147] If those guidelines are applied to wind and solar QFs larger than 100 kW, the market barriers for those smaller QFs could be mitigated as well.[148]

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[143] CREA/100, Hilderbrand/5.

[144] Idaho Power/200, Stokes/62.

[145] Idaho Power/400, Stokes/15-16.

[146] Idaho Power/400, Stokes/15-16.

[147] *See* Order No. 05-584 at 17. The Commission concluded that market barriers for QFs greater than 10 MW "will be best overcome for those QFs by improved negotiation parameters and guidelines and greater transparency in the negotiation process."

[148] Idaho Power/200, Stokes/63.

3. For Idaho Power, Lowering the Eligibility Cap Will Prevent Regulatory Arbitrage.

The eligibility cap for wind and solar QFs in the state of Idaho is 100 kW. Thus, reducing the eligibility cap for these types of QFs in Oregon will provide consistency between the Company's Oregon and Idaho service territory and discourage regulatory arbitrage. Over the last several years the Company has experienced increased litigation in Oregon driven largely by the higher avoided cost prices in Oregon and the higher eligibility cap for standard avoided cost prices.[149] Adopting a consistent eligibility cap will greatly reduce the incentive for QFs to game the system to take advantage of more advantageous contracting and pricing in Oregon.

G. The Commission should Conclude that a Legally Enforceable Obligation ("LEO") Requires the QF to Obligate Itself and Refusal to Contract or Delay by the Utility (Issue 6(b)).

Idaho Power proposes that the Commission conclude that an LEO exists only if both of the following conditions have been met: (1) the QF signs the contract, regardless of whether the utility signs; and (2) the utility has refused to contract or has purposefully delayed the contracting process.[150] This proposal is consistent with PURPA and recent FERC precedent relating to the creation of an LEO.

In *Cedar Creek Wind,* FERC concluded that a state cannot impose a rule finding a LEO only in those cases where a contract has been executed by **both** parties.[151] FERC did not go on to articulate a specific standard and did not decide whether a legally enforceable obligation existed in the case before it. However, FERC's dicta supports Idaho Power's proposal in this case. FERC suggested that a legally enforceable obligation may have existed in *Cedar Creek Wind*, in part, because the utility had received

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[149] Idaho Power/200, Stokes/66.

[150] Idaho Power/200, Stokes/80.

[151] *Cedar Creek Wind, LLC*, 137 F.E.R.C. P 61,006 at ¶ 30 (F.E.R.C. 2011).

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the contract signed by the QF and the utility management refused to sign it.[152] Instead, the utility "held the Agreements for over a week, making no changes, before they signed them," after the date at which the avoided cost prices changed.[153] FERC noted that the LEO language in its regulations (18 C.F.R. § 292.304(d)) was "specifically adopted to prevent utilities from circumventing PURPA's requirement that utilities purchase energy and capacity from QFs . . . by refusing to enter into a contract with a [QF]."[154] Here, Idaho Power's proposal is consistent with FERC's regulations because it requires a QF to demonstrate that a utility refused to negotiate or otherwise delayed the process prior to the creation of an LEO.

H. The Commission should Approve Idaho Power's Proposed Mechanical Availability Guarantee ("MAG") (Issue 6(b)).

Idaho Power recommends that standard contracts continue to include a MAG; however, the Company requests that its current standard contract be modified to more closely align with the performance guarantees contained in Idaho Power's approved Idaho standard contract.[155] Specifically, the contract should include an adjusted MAG for all intermittent QF PPAs to an 85 percent monthly availability standard. If the 85 percent MAG is not achieved, then the monthly price is adjusted with an "availability shortfall price." The Company also proposes a modification for non-intermittent resources to introduce a 90 percent/110 percent monthly performance standard. A "shortfall energy price" would be applied to deliveries outside of the 90/110 performance band.[156]

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[152] *Id.* at ¶ 38.

[153] *Id.*

[154] *Id.* at ¶ 32.

[155] Idaho Power/300, Stokes/2.

[156] Idaho Power/300, Stokes/2.

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Parties are critical of the MAG and claim that it is unnecessary because QFs have every incentive to maximize production.[157] This ignores the fact that the MAG is also necessary for scheduling and forecasting energy delivery and therefore provides direct benefits for customers.[158] Indeed, the use of the Company's proposed monthly availability determination is tied directly to the need to schedule on a day and hour ahead basis.[159] Using a shorter time period provides incentives that the QF's equipment is mechanically ready to generate if motive force is available.[160]

I. The Fixed Price Portion of a Standard Contract should be reduced to 10 Years (Issue 6(i).

Idaho Power supports the continued use of 20 year contracts. However, the Company recommends that the fixed price portion of the contract be reduced from 15 to 10 years.[161] The current fixed price portion of the PURPA contract unfairly shifts the market energy price risk from the QF to Idaho Power's customers.[162] Idaho Power's proposal is designed to more equitably share this market energy price risk.[163]

The Coalition is critical of Idaho Power's proposal because the Coalition argues that QFs should be entitled to contracts for their entire economic lives.[164] The Coalition's argument misses the mark. Idaho Power's proposal does not seek to terminate the Company's purchase obligation under PURPA.[165] QFs will be entitled to contracts as long

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157 *See, e.g.*, CREA/100, Hildebrand/20.

158 Idaho Power/400, Stokes/40; Staff/100, Bless/41.

159 Idaho Power/400, Stokes/41.

160 Idaho Power/400, Stokes/41.

161 Idaho Power/200, Stokes/73.

162 Idaho Power/200, Stokes/73.

163 Idaho Power/200, Stokes/74; Idaho Power/400, Stokes/39.

164 Coalition/200, Schoenbeck/2.

165 Idaho Power/400, Stokes/39.

as the QF is operational. The Company's proposal is narrowly focused on the allocation of market energy price risk and seeks to more fairly share that risk—to the benefit of Idaho Power's customers.[166]

It is also important to note that historically, the difference between the QF fixed avoided cost rates and the market rates has proven to be one-sided, to the detriment of Idaho Power's customers.[167]

IV. CONCLUSION

For the reasons set forth above, the Commission should approve Idaho Power's recommendations:

- For Standard Rate Contracts – Authorizing use of the Standard Method for establishing avoided cost rates as currently implemented with the addition of a separate calculation of the energy and capacity components based upon the specific capacity contributions made by different types of QFs;
- For Negotiated Rate Contracts – Authorizing Idaho Power to continue to use, as the starting point for negotiations, the modeling methodology approved by the IPUC (this requires no change to Idaho Power's current authorization to do so in Schedule 85);
- Establishing that Idaho Power owns half of the RECs in a negotiated contract;
- Updating standard rates annually using the natural gas forecast published by EIA;
- Updating the gas price forecast and load forecast utilized in the incremental cost IRP methodology for negotiated rates annually;
- Authorizing Idaho Power to charge the cost of wind integration to wind QF projects consistent with Idaho Power's Wind Integration Study;

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[166] Idaho Power/400, Stokes/39.

[167] Idaho Power/200, Stokes/73-74.

- Lowering the standard rate eligibility cap for wind and solar QFs to 100 kW;
- Establishing that an LEO is not created by a QF until the QF demonstrates that it has obligated itself to the transaction and demonstrated that the utility is either refusing to contract or purposefully and unreasonably delaying the contracting process;
- Approving Idaho Power's proposed Mechanical Availability Guarantee language; and
- Setting the fixed price portion of a standard contract to 10 years.

Adopting Idaho Power's recommendations will ensure that the avoided cost prices paid to QFs are as accurate as possible, which ensures that Idaho Power's customers are not harmed by the QF transaction. Moreover, the Company's recommendations here are intended to create consistency across both its jurisdictions to limit the gaming and regulatory arbitrage that the Company, and the Commission, have witnesses over the last several years.

Respectfully submitted this 17th day of June, 2013.

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UM 1610 the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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