Peter J. Richardson ISB# 3195
Gregory M. Adams ISB# 7454
Richardson & O'Leary, PLLC
515 N. 27th Street
P.O. Box 7218
Boise, Idaho 83702
Telephone: (208) 938-7901
Fax: (208) 938-7904
peter@richardsonandoleary.com
greg@richardsonandoleary.com

RECEIVED
2010 DEC 22 PM 2:46
IDAHO PUBLIC
UTILITIES COMMISSION

Attorneys for Northwest and Intermountain Power Producers Coalition

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE JOINT PETITION OF IDAHO POWER COMPANY, AVISTA CORPORATION, AND PACIFICORP DBA ROCKY MOUNTAIN POWER TO ADDRESS AVOIDED COST ISSUES AND TO ADJUST THE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP	**CASE NO. GNR-E-10-04** **COMMENTS IN OPPOSITION BY THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION AND ALTERNATIVE REQUEST FOR AN EVIDENTIARY HEARING**

COMES NOW, the Northwest and Intermountain Power Producers Coalition ("NIPPC") and pursuant to that Notice of Scheduling Order No. 32131 issued on December 3, 2010, by the Idaho Public Utilities Commission (the "Commission") hereby provides its Comments in Opposition to the requested reduction in the eligibility cap for published avoided cost rates. NIPPC respectfully requests that the Commission deny the request to reduce the published avoided cost rate eligibility cap, and alternatively requests that the Commission hold an evidentiary hearing prior to issuing any order reducing the cap.

INTRODUCTION[1]

On Friday, November 5, 2010, a Joint Motion ("Motion") and Joint Petition ("Petition" or collectively the "Pleading") were lodged with the Commission by Idaho Power Company ("Idaho Power"), Avista Corporation ("Avista") and PacifiCorp, DBA Rocky Mountain Power ("Rocky Mountain" or collectively "the Utilities"). In their Petition, the Utilities asked the Commission to initiate a docket to investigate various avoided cost and other related issues regarding implementation of the mandatory purchase provisions of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[2] In their Motion, the Utilities asked the Commission to *immediately* adjust the published avoided cost eligibility cap for qualifying facilities ("QFs") from 10 average monthly megawatts ("MW") to 100 kilowatts ("kw") of nameplate capacity, on less than 14 days notice if possible.

To justify the immediate eligibility cap reduction, the Utilities focused almost exclusively on the number of wind QF contract requests being made to Idaho Power at the time of the filing. The Utilities stated, "Idaho Power has over 570 MW of new QF wind contract requests, some of which are significantly mature and close to having executed contracts." *Joint Petition and Joint Motion*, at p. 4. They speculated that "Idaho Power could have over 1100 MW of wind powered

---

1 NIPPC provided additional factual and legal background in its Answer in Opposition to the Joint Motion to Adjust the Published Eligibility Cap, which NIPPC filed on November 8, 2010 in this docket. NIPPC hereby incorporates that factual and legal background into these Comments by reference.

2 The issues identified included: system reliability; operational control; ownership and valuation of RECs; the lack of capacity provided by intermittent wind generation; the need to build/acquire capacity on the system; the associated transmission infrastructure and upgrades needed to bring additional wind generation to load; the interconnection and transmission service request process; the mechanical availability guarantee ("MAG") provision; the posting of security; liquidated damages; a standard contract template; the impact of QF generation on the integrated resource planning (IRP) process; and the increased size and scale of QF projects. *See* Order No. 32131, at p. 1, n. 1.

generation on its system in the near term, which exceeds the minimum loads experienced on Idaho Power's system this year." *Id.* The Joint Motion did not point out that the average mega-watt generation ("aMW") for these proposed wind projects – even if they all were to achieve commercial operation – would likely be approximately one-third (or less) of their nameplate capacity, which would be no more than 367 aMW. Nor did it point out that Idaho Power's average load forecasted for 2010 is 1797 aMW. *See Idaho Power 2009 Integrated Resource Plan ("IRP")*, at p. 54.

The Joint Motion does not state that the avoided cost rates are too high, and it failed to note that the avoided cost rate paid to each of the proposed wind projects would be reduced by the Idaho Power's $6.50/MWh wind integration charge. Order No. 30488, at 8-9. The contracts would also contain a Mechanical Availability Guarantee ("MAG"), which requires reduced payment to the QF if its turbines are unavailable for inexcusable reasons. *Id.* The wind QFs would also need to agree to a Wind Forecasting cost sharing to defray the costs of integrating wind. *Id.* Each of the projects that could eventually bring Idaho Power's cumulative wind capacity up to 1100 MW would include all of these provisions to protect ratepayers from the possibility of paying more than the avoided costs to Idaho Power. These provisions were all arrived upon in a compromise settlement that ended the last wind moratorium only a few years ago. *See id.*

The Joint Motion appears to assert concerns regarding system reliability and costs of integrating this level of proposed wind generation on Idaho Power's system as a basis to immediately reduce the eligibility cap for availability of the published avoided cost rates for all three investor-owned utilities. *Joint Petition and Joint Motion*, at p. 4. Yet according to the Joint Motion, Rocky Mountain Power has only 64 MW of executed wind QF contracts, and absolutely 0 MW online. *Id.* It also states Rocky Mountain Power has another 358 MW of standard wind QF contracts proposed, but provides no real details on the location of these projects or how many of these inquiries are likely to result in executed contracts. *Id.*

The Joint Motion does not state that Avista has any wind QFs online whatsoever. Although Avista has not filed for approval of any wind QF contracts, two wind QFs have filed complaints against Avista alleging that Avista has failed to negotiate in good faith. *See* Case Nos. AVU-E-10-05, AVU-E-10-06. Those two QFs, if successful in litigating against Avista, would contract to sell a cumulative output of 20 MW, and if successful in achieving commercial operation would be the very first wind QF projects on Avista's system, and perhaps the only wind projects whatsoever on the system that Avista would need to integrate at the time they propose to come online.[3]

The Joint Motion makes no mention of other QF resources, and, most importantly, nowhere does the Joint Motion state that the published avoided cost rates are too high. In short, the Joint Motion states that the Commission should reduce the eligibility cap for published avoided cost rates to 100 kw in order to "establish greater administrative control of contracts during pendency of the Commission's and parties' investigation of the issues," which run the gamut from a proper delay security amount to cost-sharing on transmission upgrades. *Joint Petition and Joint Motion*, at p. 6. From the Utilities' filings to date, it is not even clear upon what basis they would rely to support an argument that the current avoided cost rates exceed their actual avoided costs.

---

[3] NIPPC relies upon Avista's 2009 Integrated Resource Plan, pages 2-15 to 2-21, which lists the Stateline project as its only wind project and states Avista's contract with 35 MW from that project expires in 2011. Although Avista has been planning to build the Reardon wind farm, for which it has purchased development rights, it is not clear that Avista is proceeding with its plan to have that project online in 2012. *See Avista 2009 Integrated Resource Plan*, at p. 8-10.

In response, in Order No. 32131, the Commission opened this docket. However, in doing so, it refused to act on the Utilities' Joint Motion to immediately reduce the eligibility cap. In refusing to immediately act on that request, the Commission stated:

> The Petitioners also request that while the investigation is pending, the Commission lower the published avoided cost rate eligibility cap immediately "on fewer than fourteen days notice, if possible." Petition at 7. The Petitioners note that a reduction in the eligibility cap on an interim basis was previously authorized in Case No. IPC-E-05-22. However, there is a significant difference between the Joint Petition in this case and Idaho Power's request to temporarily lower the eligibility cap in the 05-22 case. In the 05-22 case, Idaho Power's petition was accompanied by supporting testimony. The Commission subsequently conducted an evidentiary hearing and oral argument to develop the record.

Order No. 32131 at p. 5. Although finding, by inference, that there is no record upon which to base a decision on the requested reduction in the eligibility cap, the Commission did not ask for testimony to be lodged, nor did it schedule evidentiary hearings. Rather, the Commission's order requires only "comments in support or opposition" followed by an oral argument that is scheduled for January 27, 2011. Order No. 32131 at p. 6. In addition to setting a schedule for filing comments (December 22), and reply comments (January 19), the Commission stated that it was the Commission's "intent" that the effective date of its decision on the Utilities' requested reduction in the eligibility cap will be December 14, 2010. Order No. 32121 at p. 5.

In addition to receiving comments on the requested reduction in the eligibility cap, the Commission asked that the parties comment on whether such a reduction should apply to non-wind QFs and the "consequences of dividing larger wind projects into 10 aMW projects to utilize the published rate." Order No. 32121 at p. 5. Once the Commission decides the question regarding the requested reduction in the QF eligibility cap, the Commission will move to a new phase of the case in order to explore the other PURPA issues raised in the Joint Petition.

COMMENTS

A. REDUCING THE ELIGIBILITY CAP WOULD FRUSTRATE THE FUNDAMENTAL PURPOSE OF PURPA, IN VIOLATION OF THAT FEDERAL LAW

One of the primary reasons Congress passed the mandatory purchase provisions of Section 210 of PURPA was that Congress felt that "traditional electricity utilities were reluctant to purchase power from, and sell power to, the nontraditional facilities" and that this reluctance "impeded the development of nontraditional generating facilities." *FERC v. Mississippi,* 465 U.S. 742, 750, 102 S.Ct. 2126, 2132-2133, 72 L.Ed.2d 532 (1982). "In order to overcome [this problem] § 210(a) directs FERC, in consultation with state regulatory authorities, to promulgate such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring utilities to offer to sell electricity to, and purchase electricity from, qualifying cogeneration and small power production facilities." *Id.*, 456 U.S. at 751, 102 S.Ct. at 2133 (internal quotation omitted).

In the docket in which the Commission adopted the 10 average monthly megawatt cap for entitlement to the published rates (consolidated docket nos. IPC-E-04-8 and IPC-E-04-10) Commissioner Smith questioned the expert witnesses representing Idaho Power, U.S. Geothermal and Mr. Lewandowski and Mr. Schroeder as to the purpose of PURPA. Specifically she asked Mr. Runyan (U.S. Geothermal), Mr. Gale (Idaho Power) and Dr. Reading (Lewandowski/Schroeder) the following questions:

> Mr. Runyan, it occurs to me that this is a good opportunity for me to take advantage of your experience and a lot of times when you sit on a case like this and you have engineers talking to you about things that you really don't understand because you didn't take physics, it occurs to you that the main purpose of having a commission is to direct the policy of what you're dealing with, and so with your experience with PURPA, what do you think the purpose, the public policy purpose of PURPA is?

IPC-E-04-8 IPC-E-04-10 (consolidated) at Tr. 247

> Dr. Reading, earlier today I had the opportunity to ask Mr. Runyan his opinion about the purpose of PURPA and I'd be interested in your thoughts on that as well.

Id. at Tr. 300.

> [To Mr. Gale] I just wanted to give you the opportunity even though you say you're new to PURPA to answer the same question that I asked Dr. Reading and Mr. Runyan about the policy behind PURPA, why we have PURPA and what the Commission needs to be aware of so that we're implementing that policy.

Id. at Tr. 483 – 484.

None of the witnesses explained, as the U.S. Supreme Court did, that one of the fundamental reasons for the mandatory purchase requirement is that the Utilities have been found to be reluctant to purchase electricity from "nontraditional facilities." The result of that docket, the 10 average monthly MW eligibility cap, indicates that the Commission clearly understood its role in implementing PURPA, even if the witnesses were unable to clearly articulate that role. Excerpts from the transcript containing the complete exchange are attached as Exhibit A to these Comments.

In responding to Commissioner Smith's question, Mr. Gale on behalf of Idaho Power, tried to avoid a direct answer by stating that by simply issuing Requests for Proposals via the Utilities' IRP would serve "a lot of the same purposes. . . PURPA is trying to accomplish." *Id.* at Tr. 484. In response, Commissioner Smith corrected Mr. Gale with the following exchange:

[Commissioner Smith]	Q. But PURPA is still the law; right?
[Ric Gale]	A. Still the law.

Id.

As the Commission considers its proper role in implementing PURPA in the context of this case, it is important to keep in mind both the Supreme Court's finding that Utilities are reluctant to purchase QF power and that PURPA is, indeed, still the law.

B. THE COMMISSION'S PROCEDURAL SCHEDULE VIOLATES THE FILED RATE DOCTRINE AND THE PROHIBITION AGAINST RETROACTIVE RATEMAKING.

The effective date of the Commission's decision on the eligibility cap issue is purported to be December 14, 2010. While finding, impliedly, that there was no record upon which to base its decision on that issue on the date of Order No. 32121, the Commission created a procedural schedule and oral argument date that take place well *after* the proposed effective date. With oral argument scheduled for January 27, 2011, it is reasonable to not to expect to see the Commission's order on this important issue until early in February 2011. That this schedule is problematic and unwieldy is discussed in detail below. The Commission's proposed schedule is illegal and violates fundamental ratemaking principles: namely, the filed rate doctrine and the prohibition against retroactive ratemaking.

The sole reason the Commission made its "intent" to make the effective date of its decision on the eligibility cap retroactive is that it must anticipate that it may order a reduction in that cap. The Commission cannot simply make its orders retroactive by virtue of giving notice that it may make a change in an existing rate or order at some indeterminate time in the future. Such regulatory practices would violate the filed rate doctrine.

The filed rate doctrine is a fundamental tenant of regulated utility law that has been repeatedly and wholeheartedly endorsed by this Commission. As the Commission recently observed:

> The filed rate doctrine is a basic principle of utility regulation that was embodied in *Idaho Code* §§ 61-313 and 61-315 shortly after the turn of the 20th century when our Public Utility Laws were first adopted (1913). It also has a long history and precedent with the federal regulatory system and the United States Supreme Court. Simply put, the filed rate doctrine states that a utility may charge only the approved rates and charges it has on file with its regulatory body, i.e. its approved tariff on file with the Commission.

Order No. 30431 at p. 6. According to the filed rate doctrine, the Utilities are required to apply currently effective tariffs and/or Commission orders and are prohibited from deviating from those tariffs and/or orders until they are duly changed by the Commission. *Id.* This doctrine "embodies the policy which has been adopted by Congress in the regulation of interstate commerce in order to prevent unjust discrimination." *Id.* at p. 7 (quoting *Maislin Industries, U.S., Inc., v. Primary Steel, Inc.* 497 U.S. 116, 127, 110 S.Ct. 2759, 2766 (1990)). Therefore the Utilities are legally required to continue use of the 10 average monthly MW eligibility cap for published rates until or unless the Commission changes it. Between December 14, 2010 and sometime in February 2011, should the utilities be offered PURPA contracts for projects larger than 100 kw they will be obligated to execute the same.

The prohibition against retroactive ratemaking requires commissions to set rates prospectively and not reach back in time to alter a, heretofore, valid rate. Not only are utilities bound by the filed rate doctrine, but regulatory commissions are as well. As the U.S. Supreme Court in *Arkansas Louisiana Gas v. Hall* 453 U.S. 571, 578, 101 S.Ct. 2925, 2930, 69 L.Ed 2d 856 (1981) declared:

> Not only do the courts lack authority to impose a different rate than the one approved by the Commission, but the Commission itself has no power to alter a rate retroactively. When the Commission finds a rate unreasonable, it "shall determine the just and reasonable rate . . . to be *thereafter* observed and in force." § 5(a), 52 Stat. 823, 15 U.S.C. § 717d(a) (emphasis added). *See, e.g., FPC v. Tennessee Gas Co.*, 371 U.S. 145, 152-153 (1962); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956). This rule bars "the Commission's retroactive

> substitution of an unreasonably high or low rate with a just and reasonable rate." *City of Piqua v. FERC, supra,* at 12, 610 F.2d at 954.

Thus, this Commission, just like FERC, has no power to alter a rate retroactively. Should the Commission find that the eligibility cap should be lowered based on a valid evidentiary record, only then would be the Commission have the power to lower the cap on a prospective – going forward – basis only.

The filed rate doctrine is applicable not only to the fixed rates charged by a utility. It is also applicable to formulae, services, and methodologies. See *In Re Universal Service Fund Telephone Billing Practice Litigation* 619 F.3rd 1188, 1198 (10th Cir. 2010) in which the Tenth Circuit Court addresses a line of cases in the telecommunications context wherein the filed rate doctrine was found to be applicable to "price, service, provisioning and billing of telecommunication services". See also *Transwestern Pipeline Co. v F.E.R.C.* 897 F.2d 570, 578 (D.C. Cir. 1990) in which the D.C. Circuit Court notes that the filed rate doctrine does "not confine rates to specific, absolute numbers but may approve a tariff containing a rate 'formula' or a rate 'rule.'" Also instructive is *Occidental Chemical Corporation v. Louisiana Public Service Corporation* 494 F.Supp.2d 401 (M.D.La. 2007) which discusses applicability of the filed rate doctrine to an "avoided cost methodology." *Id.* at 417. Although the eligibility cap is not a rate, per se, that fact does not exempt the application of the filed rate doctrine to it.

The eligibility cap is not a mere 'practice' or even a tariff advice. The current eligibility cap was adopted by this Commission in a contentious and vigorously litigated docket. (Order No. 29632 in consolidated docket nos. IPC-E-04 and IPC-E-04-10.) That case took eight months to prosecute and ended up with a transcript of almost seven hundred pages (not including exhibits). The evidentiary hearing lasted two days. The Commission took testimony from expert witnesses offered by the Staff, all three of the Utilities as well as other parties. The Commission's decision was well informed by a robust evidentiary record. The fact that the decision was well informed is highlighted by the Commission's unusually detailed findings:

> The Commission finds that the parties have persuasively established the unreasonableness of using a simple 10 MW nameplate capacity rating to determine posted rate eligibility. For QF projects with parasitic load requirements such as U.S. Geothermal, such a standard would be inequitable. It is also unreasonable for low capacity factor resources such as wind. The Commission finds that the Company proposed meter energy test, a 10,000 kWh per hour limit is operationally too restrictive. The Commission believes that QF generation should not be measured on an hourly, daily or weekly basis, but rather on a monthly basis. It is on a monthly basis that QFs are paid. We find that the 10 MW threshold limit, however, must have some import, some significance if eligibility is to mean anything. The Commission finds it reasonable to define firmness as predictability on a monthly basis. By way of eligibility criteria, we find it reasonable for the utility to make an initial capacity determination and require that the QF demonstrate that under normal or average design conditions the project will generate no more that 10 aMW in any given month. To provide further definition and sideboards, we also find it reasonable to cap the maximum monthly generation that qualifies for published rates at the total number of hours in the month multiplied by 10 MW.

The time and effort that went into developing the criteria for eligibility to the published avoided cost rates underscores the applicability of the filed rate doctrine to the criteria adopted by the Commission in that docket. Any other construction would eviscerate the very concept of the filed rate doctrine. In addition, the Commission did not establish the current rate methodology with a "subject to refund"-like caveat that would have put QF developers , wind or otherwise, on notice that the current QF rate eligibility cap is subject to future change. Many developers have reasonably relied on the current methodology and are entitled to do so until it is changed pursuant to a valid Commission order that is applied on a prospective basis.

C. THE COMMISSION'S PROCEDURAL SCHEDULE CREATES UNCERTAINTY.

In the time period between the effective date and the final order, QFs hoping to contract with the utilities must decide whether to continue with their projects, and will have no idea if the published rates will apply to their project. This creates a situation where the QFs would have to be willing to sign an agreement without certainty from the Commission as to whether the published rates apply to their project. This will surely chill the market for QFs, and the Commission should make its order effective on the date of its decision, not some point earlier. Prospective QF developers must incur substantial time and expenses to progress to the point of execution of a power purchase contract. A long term contract must provide certainty to the developer that the rates within it will be enforceable. Without a long term contract with enforceable rates financing the project will be impossible. The Commission's order creates uncertainty with regard to the applicability of the published rate schedule, and will create a cloud over all contract negotiations. The Commission should immediately clarify that its ruling on the eligibility cap issue will be effective only after it issues an order on the issue to prevent uncertainty in the market.

D. THE COMMISSION'S PROCEDURAL SCHEDULE IS NOT DESIGNED TO CREATE AN EVIDENTIARY RECORD, AND THE COMMISSION SHOULD HOLD AN EVIDENTIARY HEARING PRIOR TO ANY ORDER REDUCING THE ELIGIBILITY CAP.

As noted above, the Commission has found, by implication, that the Utilities have not created a record for the Commission to rely on in deciding the requested reduction in the eligibility cap. Ironically, the Commission's procedural schedule itself does not set up procedures by which the Utilities can establish an evidentiary record. The current schedule allows only for initial comments, reply comments "addressing arguments and positions raised by the initial comments," and oral argument. Order No. 32131, at p. 6. The procedure contains no opportunity for filing of testimony or cross examination of witnesses on the eligibility cap issues. Without an evidentiary hearing, no fully developed evidentiary record will exist for this important matter. That is entirely improper because the issues before the Commission are essentially factual – the number of QF requests and the Utilities' ability to process and accept the energy and capacity offered. NIPPC therefore requests that the Commission hold an evidentiary hearing to address the eligibility cap issue raised by the Utilities. At such a hearing, the Utilities will have the burden to establish with their evidence that their requested reduction to 100 kw for all QF resources is warranted and necessary to protect ratepayers and system reliability.

E. A DROP IN THE ELIGIBILITY CAP IS NOT WARRANTED BECAUSE THE RECORD DOES NOT DEMONSTRATE THAT IDAHO POWER WILL BE UNABLE TO INTEGRATE THE AMOUNT OF WIND PROPOSED, OR THAT THE CURRENT WIND INTEGRATION CHARGE IS AN INACCURATE REFLECTION OF THE INTEGRATION COSTS.

The Utilities' Pleading provides no basis to conclude that the current wind integration charge is inadequate to compensate each Utility for its integration costs, even at the level Idaho Power states it may have on its system – 1100 MW of total nameplate capacity. The Joint Motion omits the fact that Idaho Power's most-current wind integration study – which it has not seen fit to amend with an updated filing at the Commission since November 2007 – resulted in a settlement setting the current wind integration charge without setting a cap on the overall amount of wind penetration. That study analyzed amounts up to 1200 MWs. *See Enernex's Idaho Power 2007 Wind Study*, Case No. IPC-E-07-03, p. 5 (February 6, 2007). Despite Idaho Power's statements in the Joint Motion regarding 1100 MW being near Idaho Power's minimum loads, the Enernex study concluded that even at 1200 MW of wind capacity wind would reach only 80% loads and it would do so only for a few hours per year. *See id.* at p. 35.[4]

Relying on that 2007 study, Idaho Power entered into, and the Commission approved, a settlement of the long-standing dispute over wind integration charges. Idaho Power had proposed that the availability of the published rates with a wind integration charge be limited to wind QFs cumulatively amounting to only "up to 600 MWs." *Application*, Case No. IPC-E-07-03, at p. 12. Thus, under Idaho Power's proposal, there would be an automatic cap at 600 MW, at which point a new wind moratorium would presumably ensue while Idaho Power conducted studies of penetration above that level. But the settlement and order provided for no 600 MW cap or ensuing moratorium, and instead made the avoided cost rates available to wind developers at a rate reduced by $6.50/MWh for projects coming online when Idaho Power's cumulative wind power is "501 MW and above." *See* Order No. 30488, at p. 8. The settlement and the Commission's order required Idaho Power to review its wind integration study in its IRP processes and, if necessary, request that the Commission adjust the wind integration charge upon that review. Order No. 30488, at p. 9. The Commission stated that it "expect[ed] annual review by the Company and proposed adjustments when warranted." *Id.* at p. 13.

Along those lines, Idaho Power stated in its 2009 IRP that, because it anticipated having in excess of 600 MW of wind on its system, it planned "to update its wind integration study in the first half of 2010 . . . . The updated study will incorporate planned increases in wind

4 Idaho Power itself believed at that time that 1200 MW would overwhelm "the ability of system *as represented by the modeling software* (*Vista* DSS) to consistently maintain the required amount of regulating service." *Idaho Power's Introduction to Enernex's Idaho Power 2007 Wind Study*, Case No. IPC-E-07-03, p. 3 (February 6, 2007) (emphasis added); *see also Addendum to Idaho Power's 2007 Wind Study*, Case No. IPC-E-07-03, p. 26 (Oct. 31, 2007). But as discussed below, the modeling in the 2007 study did not take into account the operating reserves that may be provided by the Company's gas-fired resources, including the Langley Gulch facility that will soon be online.

generation as well as the capability of the new Langley Gulch CCCT to provide additional operating reserves." See *Idaho Power 2009 IRP* at p. 18. This statement in Idaho Power's IRP indicates that Idaho Power must know that the addition of Langley Gulch will expand its ability to integrate wind, and likely reduce the cost to do so. Indeed, the 2007 wind study focused mainly on the Company's Hells Canyon complex as the wind balancing resource, and did not consider the balancing capacity of the 300 MW Langley Gulch combined cycle gas plant, which will be online in 2012. *See Application*, Case No. IPC-E-07-03, at p. 6; *Addendum to Idaho Power's 2007 Wind Study*, at p. 1; *Idaho Power 2009 IRP* at p. 6; *see also Enernex's Idaho Power 2007 Wind Study*, at p. 46 (listing the Company's hydropower and coal resources as inputs to the model but not including any of the Company's gas-fired resources).

The use of the Company's current and committed gas-fired resources as balancing facilities for wind has never been taken into account in a wind study submitted to the Commission. As early as 2004, Idaho Power estimated in its IRP that "in order to safely integrate 1000 MW of intermittent wind generation, it would be necessary to contemporaneously add 640 MW of combustion turbines to add capacity when the intermittent wind resources were not operating." Order No. 29839, at p. 4. Today, Idaho Power has a 271 MW gas-combustion facility at Danskin, a 173 MW gas-combustion facility at Bennett Mountain, and is constructing the 300 MW Langley Gulch plant for operation in 2012. *Idaho Power 2009 IRP* at pp. 6, 32. That amounts to 744 MW of combustion turbine capacity in addition to the hydro firming capacity studied in detail in the 2007 wind study! This is a critical point. Idaho Power's own IRP declared that it would have no trouble integrating 1,000 MW of wind if it had 640 MW of combustion turbines. In a few short months Idaho Power will have 744 MW of combustion turbines on line – which should be sufficient to allow Idaho Power to accommodate all of the wind projects it claims to be knocking on its door.

In the years since 2007, the Company has built and started constructing new potential wind-firming resources. Yet Idaho Power has not provided its updated wind integration study to date, or proposed to increase the wind integration charge. An IRP cycle has come and passed, and so has the time the Company set for release of its new wind integration study in the first half of 2010. The Company's decision not to update these studies demonstrates either negligence on its part, or that the current wind integration charge accurately reflects the costs to integrate the wind. NIPPC submits that it would be foolish to assume Idaho Power has been negligent in its efforts to make sure the wind integration charge is high enough. The Commission cannot conclude based on the record presented that Idaho Power is unable to integrate the proposed wind projects, and there is no basis to make a reduction in the eligibility cap for Idaho Power's published rates effective December 14, 2010.

As for Rocky Mountain Power and Avista, the filings to date have not even made the case that either utility has any PURPA wind projects online, or that either is facing a large amount of wind inquiries in Idaho. NIPPC will reserve its comments on the amount of wind those utilities may be able to integrate until such time as they have provided some basis for the proposition that they are anywhere near approaching such a level.

F. AGGREGATING SMALL WIND QFs BY THE SAME DEVELOPER IS APPROPRIATE BECAUSE THE UTILITY IS STILL PROVIDING A CONTRACT AT THE AVOIDED COST RATE.

The Idaho Commission has essentially adopted the FERC one-mile-rule for use in determining when QFs sharing a common owner are entitled to Idaho's published avoided cost rates. The applicable FERC rule interprets a provision of the Federal Power Act, which limits eligibility for QF status to facilities with "a power production capacity which, together with any other facilities located at the same site (as determined by the [FERC]), is not greater than 80 megawatts." 16 U.S.C. § 796(17)(A); *see also* 18 C.F.R. § 292.204(a).[5] FERC's regulation states that "the power production capacity for which qualification is sought, together with the power production capacity of any other . . . small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts." 18 C.F.R. § 292.204(a)(1). "[F]acilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought." *Id.* at § 292.204(a)(2)(i).

FERC adopted this one-mile separation rule with its initial PURPA regulations decades ago, and has rejected attempts to alter since then. In FERC's most recent rule-making regarding PURPA's mandatory purchase provisions, a large utility group requested that FERC "revisit the 'one-mile-rule' used to determine whether two facilities are part of the same QF for purposes of § 292.204(a)." *Revision to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production Facility*, 75 Fed. Reg. 15950, 15955 (March 30, 2010). The utility group asked "that the Commission adopt a rebuttable presumption that facilities on sites located more than one mile apart are independent for purposes of QF certification, but that utilities would be allowed to rebut this presumption upon a showing that the facilities, although located more than one mile apart, are 'part of a common enterprise' and

---

5 PURPA imposes no size limitation to be a QF for projects which are an "eligible solar, wind, waste, or geothermal facility" as defined in section 3 of the Federal Power Act, 16 U.S.C. § 796(17)(E), but that section of the Federal Power Act only exempts facilities certified prior to 1994 and constructed prior to 1999. *See* 16 U.S.C. § 796(17)(E).

should thus be considered as a single entity, not entitled to more separate certifications of QF status." *Id.*

FERC rejected the utility proposal to undermine its one-mile-rule, observing that the one-mile-rule has been part of its regulations since the inception of PURPA. *Id.* And the rule remains today that two qualifying facilities up to 80 MW in capacity may be owned by the same entity yet still be PURPA "small power production facilities," so long as they are separated by one mile. FERC's obvious intent is to promote development of relatively large renewable energy facilities through PURPA. This intent is further evidenced by FERC's recent order declaring that the Public Utility Commission of Texas must allow several QFs commonly owned by John Deere Renewables to enter into long-term contracts at avoided cost rates calculated at the time they incurred an obligation to deliver the output of their wind facilities to a utility. *See JD Wind 1, LLC, JD Wind 2, LLC, JD Wind 3, LLC, JD Wind 4, LLC, JD Wind 5, LLC, JD Wind 6, LLC*, "Notice of Intent Not to Act and Declaratory Order," 129 FERC ¶ 61,148, at ¶¶ 24-29 (November 19, 2009). FERC recognized that these projects were each "wholly-owned subsidiaries of the John Deere Renewables, LLC," and that "[a]ll of the J.D. Wind QFs [we]re 10 MWs, except for J.D. Wind 4, LLC, which [wa]s 79.8 MW." *Id.* at ¶ 2, & n.4. FERC knew these wind projects were developed by one large, sophisticated developer utilizing the one-mile-rule to break up a 129.4 MW project into smaller projects to qualify below the 80 MW limit. But FERC nevertheless ordered that these were entitled to PURPA contracts.

The Idaho Commission has essentially adopted FERC's one-mile-rule for determination of QF size eligibility for entitlement to the published rates. In other words, commonly-owned QFs using the same energy resource, and sized up to 10 aMW are entitled to the published rates so long as they are separated by one mile. *See* Order Nos. 26772, 26966, 30415. The

Commission rejected attempts to require QFs taking the published rates to separate their projects by five miles in Order No. 30415. The Utilities now renew their claim that QFs are "gaming" the system and taking advantage of economies of scale by aggregating projects. But this is an improper attempt to shift the focus of the debate away from the utilities' avoided costs and instead focus on the cost to the QFs to build their projects. If the published rates are a true approximation of the utilities' avoided cost for the next incremental unit of generation, then there is no reason to deny QFs the right to aggregate several small projects.

CONCLUSION

For the reasons set forth above, NIPPC respectfully requests that the Commission deny the request to reduce the published avoided cost rate eligibility cap, and alternatively requests that the Commission hold an evidentiary hearing prior to issuing any order reducing the cap.

Respectfully submitted this 22nd day of December, 2010.

RICHARDSON AND O'LEARY, PLLC

Peter J. Richardson (ISB No: 3195)
Gregory M. Adams (ISB No. 7454)
Attorneys for the Northwest and
Intermountain Power Producers Coalition

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 22nd day of December, 2010, a true and correct copy of the within and foregoing **COMMENTS IN OPPOSITION BY THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION** was served by ELECTRONIC MAIL and US MAIL, to:

Donovan E. Walker
Lisa Nordstrom
Idaho Power Company
1221 West Idaho Street
Boise, Idaho 83707-0070
dwalker@idahopower.com
lnordstrom@idahopower.com

Daniel E. Solander
Rocky Mountain Power
201 South Main
Salt Lake City, UT 84111
Daniel.solander@pacificorp.com

Michael G. Andrea
Avista Corporation
1411 East Mission Avenue – MSC-23
Spokane, WA 99202
Michael.andrea@avistacorp.com

Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 West Washington
Boise, Idaho 83702
Jean.jewell@puc.idaho.gov

Don Sturtevant
Energy Director
J. R. Simplot Company
ONE CAPITAL CENTER
999 Main Street, P.O. Box 27
Boise, Idaho 83707-0027
Don.sturtevant@simplot.com

Ronald L. Williams
Williams Bradbury,P.C.
1015 W. Hays St.
Boise ID, 83702
ron@williamsbradbury.com

Scott Montgomery
President, Cedar Creek Wind, LLC
668 Rockwood Drive
North Salt Lake, Utah 84054
scott@westernenergy.us

Dana Zentz
Vice President, Summit Power Group, Inc.
2006 E. Westminster
Spokane, W A 99223
dzentz@summitpower.com

Scott Woodbury
Idaho Public Utilities Commission
472 W. Washington (zip: 83702)
P.O. Box 83720
Boise, ID 83720-0074
Scott.Woodbury@ipuc.idaho.gov

Robert A. Paul
Grand View Solar
15960 Vista Circle
Desert Hot Springs, CA

robertpaul@gmail.com

Thomas H. Nelson
Renewable Energy Coalition
PO Box 1211
Welches, OR 97067
nelson@thnelson.com

James Carkulis
Managing Member
EXERGY DEVELOPMENT GROUP OF IDAHO, LLC
802 West Banock Street, Ste. 1200
Boise, Idaho 83702
jcarkulis@exergydevelopment.com

Glenn Ikemoto
Margaret Rueger
Idaho Windfarms, LLC
glenni@EnvisionWind.com
Margaret@EnvisionWind.com

R. Greg Ferney
Mimura Law Offces, PLLC
2176 E. Franklin Rd., Suite 120
Meridian, ID 83642
greg@mimuralaw.com

Bill Piske, Manager
Interconnect Solar Development, LLC
1303 E. Carter
Boise, ID 83706
bilpiske@cableone.net

Dean J. Miller, Esq.
McDEVITT & MILLER LLP
P.O. BOX 2564-83701
Boise, Idaho 83702
ioe@mcdevitt-miller.com

Paul Martin
Intermountain Wind LLC
P.O. Box 353
Boulder, Colorado
paulmartin@intermountainwind.com

By: Nina M. Curtis
Nina M. Curtis

EXHIBIT A

I N D E X

I N D E X

I N D E X

a whole generated 70 percent, is it? Your testimony is that that represents an Idaho Power specific number?

A Yes.

Q You're not testifying here today as to what the experience may be with Avista or PacifiCorp or somebody other than Idaho Power?

A No. I have not looked at them.

MR. STRONG: Thank you. That's all I have.

COMMISSIONER SMITH: Do we have questions from the Commission?

EXAMINATION

BY COMMISSIONER SMITH:

Q Dr. Reading, earlier today I had the opportunity to ask Mr. Runyan his opinion about the purpose of PURPA and I'd be interested in your thoughts on that as well.

A Well, the purposes of PURPA in my mind, I'm thinking for a minute because there's many purposes, I think, for PURPA, certainly diversity is one that you discussed. It's also to try to install some measure of competitiveness to the monopoly, electric industry at least monopoly, at the time PURPA was passed. It is aimed at -- boy, I could give you my economics lecture here.

Q No lectures.

A That it's a check on the utility with the Averich-Johnson effect where it's been shown that monopolies tend to want to gold plate rate base because that's where they get their rate of return, so in part it was lobbied and passed because of that. I think PURPA is a good law and I think what I didn't realize at the time is that it provides not only a good check for looking at what a utility's resource is in building going forward, I think it also provides a check to regulatory agencies on what the value of conservation is and gives a measuring stick so that regulatory commissions don't get too far off the ranch either one way or the other.

I'm not sure I'm saying that very well, but if you have an avoided cost rate and it goes through a hearing process and it's established and it's thought out, then you have a very good measuring stick about what energy and electricity is worth, and when you do your whole set of regulatory things, you can always look over your shoulder and say we have that benchmark to look at.

COMMISSIONER SMITH: Okay, thank you.

Do you have redirect, Mr. Richardson?

A There's two angles to look at it. One is to the extent that they can take measures, now there's a reason to take measures. To the extent that there are things beyond their control, what it does do is now it values the product we're getting more correctly.

Q But if they don't produce, then they don't get paid?

A Correct.

Q And if the Company has to go out and buy power, for some reason it doesn't have the resources on its system or loads are more than you predicted and you can't squeeze by, where do those costs go?

A Well, they'll go through the power cost adjustment and, Commissioner Smith --

Q I'm listening.

A -- if they don't produce and the damages are exacted, those will go through the power cost adjustment as well, so the customers are expecting to get that energy delivered from the QF. If it doesn't happen and it's to the customer's detriment, then the QF gets to contribute to the PCA.

Q I want to go back to this volunteer issue because I'm curious how can the Company be seen as a volunteer as long as PURPA is the law and there's a must purchase requirement and this Commission approves contracts and you mentioned your experience in three states in QF contracts at your own peril, so could you please expand on that so I can understand how anybody, especially given the history of your Company since 19 whatever, in the area of QF contracts could ever be seen as a volunteer on these contracts.

A It's a particular aspect of it. When the deregulation activity was going on, and the three states I'm talking about was here in our own workshops and in Oregon and in Nevada, the idea of stranded costs came up, as you might recall, and along with the stranded costs were the possibility of overpriced, arguably overpriced, PURPA contracts, and in each state, as I recall, was not the argument of those that you'd entered into up until that time, but the mere fact that we had NEPA 92 and deregulation on the horizon that any future contract that a company might enter into in that environment, shame on them if they didn't protect themselves contractually. That's what I'm referring to and that's what we're trying to provide here.

Q So was that a position of the Idaho Commission?

A I don't know that it was your position, in fact, it probably wasn't your position, but it was a discussion item in our deregulation workshops.

Q So it was just a discussion item in deregulation workshops that probably happened eight years ago in a state where the legislative committee has emphatically say we're not going there, not now, not ever, no way?

A I hear what you're saying.

Q Okay; so was it any more firm in Oregon?

A I think it was brought up in all the states.

Q But was it any more firm? Is it a state policy? Is it in their statute? Is it in a commission order?

A I don't know if it's in their statute because we're exempted from their part, but from my aspect, if it's an issue that is brought up in an open discussion and if we don't take some action to mitigate it, then it's just foolish from our end regardless of how remote it is.

Q I understand. The other thing that occurred to me that this incentive could be is a strategy on the part of the Company to force these projects into the RFP process so you pay prices lower than the QF rate.

A I don't know what the prices will bring in the RFP process, but I'm eager to see.

Q Okay, and finally, I just wanted to give you the opportunity even though you say you're new to PURPA to answer the same question that I asked Dr. Reading and Mr. Runyan about the policy behind PURPA, why we have PURPA and what the Commission needs to be aware of so that we're implementing that policy.

A Well, I'm not sure that I'm going to differ much from Mr. Runyan's answer. I think initially it was put in to provide some other sources of generation. To the extent it provides a discipline to the Company's resources like Dr. Reading said, that's fine, too. In today's age, I think an IRP that has teeth in it with diverse portfolios that go out for RFPs could serve a lot of the same purposes. The only place where I see a disconnect is in the very small ones who wouldn't maybe be able to participate, but potentially even the IRP RFPs could become the new avoided cost because we'll have a market test for those, but be that as it may, I think an IRP process with teeth could do a lot of what PURPA is trying to accomplish.

Q But PURPA is still the law; right?

A Still the law.

Q So the Commission still has the obligation to calculate an avoided cost rate?

A And maybe costs could be based on IRP results.

Q So you think there's flexibility there?

A Yes.

Q But you haven't asked us to do that?

A No.

COMMISSIONER SMITH: All right, I think that's all I have.

Redirect, Mr. Kline?

MR. KLINE: I do have a couple. It looks like we're going to be going tomorrow anyway or do you have a feel for going late?

COMMISSIONER SMITH: Well, we can go off the record for a minute.

(Off the record discussion.)

COMMISSIONER SMITH: We'll go back on the record.

REDIRECT EXAMINATION

BY MR. KLINE:

Q In a question to you from Mr. Richardson, he stated that the Commission has not issued an order that distinguishes QF resources between non-firm and firm. Do you recall that question to you?

A Yes.

Q Isn't it true that Idaho Power has filed

COMMISSIONER SMITH: Are there questions from the Commission?

EXAMINATION

BY COMMISSIONER SMITH:

Q Mr. Runyan, it occurs to me that this is a good opportunity for me to take advantage of your experience and a lot of times when you sit on a case like this and you have engineers talking to you about things that you really don't understand because you didn't take physics, it occurs to you that the main purpose of having a commission is to direct the policy of what you're dealing with, and so with your experience with PURPA, what do you think the purpose, the public policy purpose, of PURPA is?

A Initially, and I think it still holds true today, is to encourage a diverse supply of energy. It was in response to the oil shortage, so a diversity in supply of energy and the way it seems to me that the state took it one step further is it said we like the idea of diversity, but we only want to have the exposure limited to so-called 10 megawatt plants.

Q Because part of our purpose is to protect ratepayers from undue financial conditions or burdens;

correct?

A Correct, and that's why the Commission is empowered to set the rates, the avoided cost rates, and we've had those hearings and the SAR is now in place.

Q Do you think this goal of diversity in supply is any less important today than it was when PURPA was enacted?

A No, I think it's more important.

Q And so in your opinion, if the Commission is going to achieve this purpose of having diversity in supply, recognizing that we've put appropriate safeguards around it in terms of size and rate so that ratepayers aren't adversely impacted, what's the right answer in this case?

A The right answer in this case is to stick with a well-proven contract methodology. The facts show that the project has consistently performed at levels that are very acceptable and the Commission has gone through over the years a capacity and energy payment which was deemed too risky and in fact, was encouraged by the utilities to go to an energy payment only for delivered energy and with that change, we've had a very stable situation that gets the performance out of the projects, that's the desired performance, and does it in a way that doesn't burden the developer with a number of very difficult risks that must be quantified in order to finance and build a project.

Q Now, with regard to these contracts and some contracts maybe having different features or as opposed to having just a standard contract that you sign or you don't sign, I guess I was trying to ponder whether the purpose of having a standard contract was for the benefit of QF developers or for the benefit of the utility.

A Well, I think it's to the benefit of both. It's always good for the developer to know what you're getting into on the front end. It's to the benefit of the utility because it takes less administrative burden and I think it's to the benefit of all the people involved in it because you know what you have and you're not going to get a lot of one-off type of deals.

Q Do you think there's any room for different features?

A Yes, I do. As I've stated, I think the capacity limitation and the interpretation of the Commission's intent is one that needs to be dealt with on a project-by-project basis and it's not an unreasonable burden to consider what the resource type is and to make a well-researched judgment on what's an appropriate determination of whether that meets the criteria or not and so I think there does have to be flexibility.

Q And in terms of your discussion, I think, with Mr. Strong and perhaps Mr. Fell about your goals for the QF industry as a whole and the Commission's statewide policy, would it be just enough for you if we approved the contract terms that U.S. Geothermal desires in your Idaho Power contract and didn't go for the full-blown, statewide, three-utility, multi-project policy position?

A That would be very adequate for my client.

COMMISSIONER SMITH: Thanks. That's all I had.

Do you have redirect, Mr. Ward?

MR. WARD: Just one area.

REDIRECT EXAMINATION

BY MR. WARD:

Q Mr. Runyan, Mr. Kline asked you some questions regarding the ability of PURPA developers to insist on a contract even if their capacity doesn't meet the 10 megawatt limitation. Do you recall that discussion generally?