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IDAHO PUBLIC UTILITIES COMMISSION

January 19, 2011

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
P O Box 83720
Boise ID 83720-0074

GNR
RE: **Case No. ~~IPC~~-E-10-04**

Dear Ms. Jewell:

We are enclosing an original and seven (7) copies of the REPLY COMMENTS OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION in the above case.

An additional copy is enclosed for stamping and return to our office.

Sincerely,

Nina M. Curtis

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Administrative Assistant for Peter Richardson

encl.

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Attorneys for Northwest and Intermountain
Power Producers Coalition

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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** **REPLY 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 Reply 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. NIPPC further requests that the Commission make any reduction in the cap effective on the date of the Commission's order reducing the cap, not on the retroactive and arbitrarily-determined date of December 14, 2010.[1]

REPLY COMMENTS

A. THE IRP METHODOLOGY IS FLAWED AND PRODUCES ILLEGAL AVOIDED COST RATES.

Idaho Power, Rocky Mountain Power, and Avista (collectively the "Utilities") propose to reduce the eligibility cap at which a PURPA qualifying facility ("QF") project is entitled to the Commission's published avoided cost rates from 10 average monthly mega-watts ("aMW") to 100 kilowatts ("kw"). They concede, however, that they still have an obligation to offer to purchase QF power from PURPA developers that offer projects greater than 100 kw. PURPA and the Federal Energy Regulatory Commission's ("FERC's") regulations require each of the Utilities to buy energy and capacity from QFs of all sizes at "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." 16 U.S.C. § 824a-3 (d). The Utilities and Commission Staff propose to set the avoided cost rates for projects greater than 100 kw based on the individual operating characteristics of each QF – through the "IRP Methodology." *Avista's Initial Comments*, at p. 3; *Rocky Mountain Power's Initial Comments*, at p. 4; *Idaho Power's Initial Comments*, at p. 5; *Commission Staff's*

[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, as well as extensive background and argument in its initial Comments filed December 22, 2010. NIPPC hereby incorporates its prior filings into these Reply Comments by reference. NIPPC stands by all comments made earlier, and in no way concedes any point previously made.

Initial Comments, at pp. 3-4, 12.[2] For this IRP Methodology, each utility would use the power supply model it uses in preparation of its biannual integrated resource plan ("IRP"). Idaho Power's proposed IRP Methodology will use a power supply model called Aurora. Avista is not sure which power supply model it will use. *See Avista's Response to NIPPC Request No. 23(a)* (stating Avista "would likely propose to use its AURORA and/or PRiSM models").[3] Rocky Mountain Power will use the power supply model developed by its parent company known as the Grid Model.

The solution proposed in the Utilities and Commission Staff's Initial Comments is unworkable and illegal. The current system of using published avoided cost rates for projects up to ten average monthly megawatts has been fully and exhaustively litigated and vetted. It is not perfect – hence the need for the additional tweaking that will be the subject of the next phase of this docket. The IRP Methodology, on the other hand, has rarely been used, never been litigated and has not been proven as a reliable way to estimate avoided cost rates. *See* Case No. IPC-E-95-09; Order No. 26576. Furthermore, it will be applied inconsistently and on a blind-to-developer basis. It may be possible to create an IRP Methodology that is workable, but the current methodologies being proposed by the Utilities are not capable of complying with PURPA and do not accurately reflect the Utilities' avoided costs. For the following reasons, the current IRP Methodology is flawed and illegal.

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2 Commission Staff recommends that the drop in the eligibility cap apply only to wind QFs.

3 In these Reply Comments, NIPPC cites extensively to discovery provided in this case. NIPPC will not submit the discovery into the record at this time, however, because the Commission's procedural schedule provides for no evidentiary hearing where NIPPC can fully contest all factual issues by cross-examining the witnesses providing the responses to adequately develop an evidentiary record in this matter.

1. **The IRP Methodology imposes impossible time constraints on PURPA developers.**

PURPA developers spend significant amounts of time to bring a project forward to a point the developer is confident enough to execute a contract. For example, a prudent wind developer must conduct at least two years of wind measurement to evaluate the motive force with a level of confidence necessary to invest additional resources and request power purchase and interconnection agreements. All QF project developers must spend a significant amount of time and money securing and analyzing the motive force before they are in a position to execute project contracts. There must be a high degree of certainty as to the availability of published rates for a developer to invest the time and money to do the necessary studies. But until the motive force is studied and measured, under the IRP Methodology the utilities are, by definition, unable to provide an avoided cost rate to the developer. Developers will have few incentives to even begin analyzing projects in Idaho without any prior indication that the rate may be profitable.

2. **The IRP Methodology is a black box that will instill no confidence in the PURPA development community.**

The models used by the Utilities are purchased under licensing agreements that prohibit the licensee from allowing third parties access. *See Avista's Response to NIPPC Request No. 23 (a)* (stating Avista "cannot provide the models"). As a result, the models are "black boxes" to a PURPA developer. The confidence necessary to invest vast sums of money in preliminary ground work on a PURPA project can only be engendered by complete and unfettered access to the working models used to set avoided cost rates. Allowing the Utilities to essentially hide their work inside a black box would violate this Commission's mandate to encourage the development of PURPA projects.

3. The IRP Methodology violates several of FERC's requirements for an avoided cost methodology.

FERC's implementing regulations allow states, in setting rates for purchases, to differentiate among various technologies on the basis of the supply characteristics of such technologies. 18 C.F.R. § 292.304(c)(3)(ii). However, when states take into consideration the supply characteristics of various technologies in determining avoided cost rates, they <u>must</u> incorporate a laundry list of factors that have been largely ignored by the Utilities. Incorporating FERC's list of factors in setting rates is not optional. *See* 18 CFR 292.304(e). There has been no showing that the IRP Methodology complies with several of these requirements, including the following:

> *The expected or demonstrated reliability of the qualifying facility.*
> 18 C.F.R. § 292.304(e)(2)(ii).

The Utilities have not demonstrated that they have incorporated the fact that all of the QFs on line and, hence in all likelihood all proposed QFs, are extremely reliable. Reliability is inherent in the QF's relationship with its purchasing utility because QFs simply do not get paid if they do not produce, and QFs get paid less if they fail to achieve production or availability targets. *See* Order No. 29632 (requiring PURPA QFs to agree to a PPA term whereby the utility penalizes the QF if it fails to deliver energy in an amount within 90 to 110 percent of its projected monthly generation); Order No. 30488 (allowing wind QFs to agree to an alternative penalty by which they are penalized if they are not physically capable and available to generate at full output during 85% of the hours of the month, excluding times for scheduled maintenance and events of force majeure). It is doubtful that the value of the high degree of reliability inherent in the QF commitment to deliver power is incorporated into any of the IRP Methodologies.

> *The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance.*
> 18 C.F.R. § 292.304(e)(2)(iii).

The Utilities have not demonstrated they have incorporated the unique Commission-vetted contract terms into their calculation of avoided cost rates using the IRP Methodology. For example, the Utilities just recently unilaterally started insisting on delay default liquidated damages security provisions in all new PURPA contracts in the amount of $45 per kw of capacity.[4] The Utilities have been silent on the added value to them of a QF agreeing to this delay security provision and have apparently therefore failed to account for that value in their IRP Methodologies.

> *The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities.*
> 18 C.F.R. § 292.304(e)(2)(iv).

The Utilities have not demonstrated that they have made any effort, in the IRP methodology, to coordinate scheduled outages of the QF with scheduled outages of the utility's facilities. Nor have they, as far as NIPPC is aware, assigned a value to such coordination of outages with QFs.

> *The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation.*
> 18 C.F.R. § 292.304(e)(2)(v).

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[4] For example, a 10 MW QF project must post $450,000 after contract approval, and would forfeit that entire amount if it failed to come online as scheduled, even if the market price for replacement power were below the contract price.

The Utilities have not demonstrated that they conduct, in the IRP Methodology, an analysis of the ability of QFs to provide energy and capacity during periods of system emergencies.

> *The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system.*
> 18 C.F.R. § 292.304(e)(2)(vi).

It appears from the Utilities' filing, that they ignore the aggregate value of energy and capacity from all of the qualifying facilities on their respective systems. The aggregate value of energy and capacity from all of the QFs on line is, in all likelihood, extremely valuable and apparently has historically been ignored by the Utilities in setting avoided cost rates using the IRP Methodology.

> *The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.*
> 18 C.F.R. § 292.304(e)(2)(vii).

To NIPPC's knowledge, the fact that QFs are brought on line in smaller capacity increments and with shorter lead times than utility base load units has never been considered by the Utilities in setting avoided cost rates under their respective IRP Methodologies. The costs associated with the long lead times and massive capital commitments required for the Utilities to construct new facilities are simply ignored when the Utilities determine avoided cost rates using the IRP Methodology. There is an obvious monetary value to investor-owned utilities and their ratepayers of not having to pay for construction work in progress and the elimination of the regulatory uncertainty of successfully rate-basing new construction projects. *See infra* (discussing Avista's Reardon wind project).

> *The relationship of the availability of energy or capacity from the*

> *qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use.*
> 18 C.F.R. § 292.304(e)(3).

The Utilities have not demonstrated that they have conducted an analysis of either the ability of the purchasing utility to defer capacity additions or to calculate the value in the reduction of fossil fuel use. The value associated with the reduction in fossil fuel use allowed by purchases from QFs is not incorporated into the avoided cost rates using the IRP Methodology. Future increases in coal costs are addressed in detail later below, but certainly are not included in the IRP Methodology. In addition, the cost to the utility of extreme natural gas volatility has never, as far as NIPPC understands, been added to the Utilities' avoided cost calculations under either the SAR or the IRP Methodologies. This is a value that FERC rules require to be considered which is completely ignored by the Utilities.

> *The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.*
> 18 C.F.R. § 292.304(e)(4).

The Utilities have not demonstrated that they have conducted an analysis of the savings they realize by purchases from QFs in variations in line losses. Upgraded transmission lines and related facilities paid for by QFs (as discussed in more detail below) benefit all ratepayers, reduce costs to the utility and create a more robust transmission system. Those benefits are ignored using the IRP Methodology. Furthermore, a QF located at or near load centers – such as cogenerators at large industrial facilities – create avoided transmission costs for their host investor-owned utility.

For the additional items contained in 18 C.F.R. § 292.304(e) not directly addressed, the current IRP Methodology may or may not comply with the applicable provision. But without any transparency to QF developers, there is no way to test the utility's analysis in any individual case.

4. Idaho Power's Langley Gulch plant demonstrates the wildly inaccurate avoided costs generated by the IRP Methodology.

The Commission recently granted Idaho Power a Certificate of Public Convenience and Necessity ("CPCN") to construct the Langley Gulch 330 MW natural gas fired combined cycle combustion turbine ("CCCT") in Southern Idaho. *See* Order No. 30892.

The Commission estimated that the output from Langley Gulch would cost the Idaho ratepayers approximately $126 per MWh, and Idaho Power has confirmed that cost estimate is still accurate. *Id.* at p. 6; *Idaho Power's Response to NIPPC Request No. 46(a)*. That figure is much higher than the avoided cost rates in effect at the time, but utilities in Idaho do not use their avoided cost rates as a ceiling or benchmark against which they measure the reasonableness of utility-built resources. As the Staff witness in the Langley Gulch case explained in prefiled testimony:

> I do not believe avoided cost rates used for PURPA QF contracts are a fair comparison to the cost Idaho Power will pay for power produced by the Langley Gulch plant. Although avoided cost rates are computed based on a surrogate combined cycle combustion turbine (SAR) very similar to Langley Gulch, assumptions about how the SAR and the Langley Gulch plant would be operated are much different. Avoided cost rate computations assume that the SAR plant is not economically dispatched and is instead operated at nearly its maximum achievable capacity factor. This is consistent with PURPA QFs that are not dispatchable and operate at as high a capacity factor as they can. The Langley Gulch plant clearly will be dispatchable, and will be operated only when it is cost effective to meet load or make surplus sales. Unlike the

> assumptions for the SAR or PURPA QFs, it will not be operated when it is not needed or when it is not profitable.

Direct Testimony of Rick Sterling, Case No. IPC-E-09-03, p. 83.

Now, in discovery in this case, Idaho Power has calculated the 20-year levelized rate for Langley Gulch using the IRP Methodology and concluded that, if it were modeled as a high (90%) capacity factor must-run unit as Mr. Sterling described for PURPA QFs, it would have a levelized avoided cost of $75.88/MWh. *Idaho Power's Response to NIPPC Request No. 46(d).* If a PURPA developer brought Langley Gulch to Idaho Power as a QF, the cost to the ratepayers would be approximately $50/MWh less than Langley Gulch as a dispatchable, rate-based facility. Thus, according to the IRP Methodology, the value to the ratepayers of a PURPA Langley Gulch plant is $50/MWh cheaper than the cost to the ratepayers of a dispatchable, rate-based Langley Gulch plant. The $50-difference should merely represent the value of the capacity or dispatchability of the plant, and on its face $50/MWh for capacity is far out of the realm of reality in today's market. *See Avista's Response to NIPPC Request No. 19(f)* (stating Avista's dispatchable Lancaster plant carried a fixed cost of $20.87/MWh in 2010).

Another way to look at this scenario is that the ratepayers would have a non-dispatchable 330 MW must-run plant that is operating 90% of the time. The ratepayers would realize $50/MWh in savings for <u>not</u> having a dispatchable plant at their disposal. The ratepayers could actually pay fifty dollars a megawatt hour to an off-taker to take and use the excess power and <u>*still*</u> <u>*be*</u> <u>*indifferent*</u> in terms of cost to them of either a Langley Gulch QF or a Langley Gulch rate-based facility.

Because $50/MWh is obviously a gross overestimate of the cost of dispatchability, the Langley Gulch IRP Methodology calculation demonstrates that the IRP Methodology generates a value that is far below Idaho Power's actual avoided costs. The Langley Gulch cost of $126/MWh is the real life avoided cost for Idaho Power to construct and operate a fully dispatchable generation facility; it is therefore the real-life value of Idaho Power's avoided cost for a dispatchable facility. If the IRP Methodology provided an accurate measure of Idaho Power's true avoided costs, the value it generated for the non-dispatchable Langley Gulch would be equal to the true costs for the dispatchable plant ($126/MWh) minus a reasonable cost for dispatchability, which we can assume to be even as much as the $20/MWh in the Lancaster agreement. Thus, the IRP methodology should generate a value of at least $106/MWh for a non-dispatchable Langley Gulch. That it actually generates a value of $75.88/MWh for the "Langley Gulch QF" proves that it vastly underestimates the avoided costs of QF power.[5]

B. THE COMMISSION'S PROCEDURAL SCHEDULE VIOLATES THE FILED RATE DOCTRINE.

NIPPC commented extensively on the legal and practical shortcomings of the Commission's proposal that the effective date of its eligibility cap order which will likely be issued in February, 2011, will be retroactively effective on December 14, 2010. The Commission Staff and the Utilities' Initial Comments appear to support this proposed schedule. FERC's PURPA rules prohibit discrimination against QFs in establishing avoided cost rates, including in the processes by which the Idaho Commission establishes published rates. *See* 18 C.F.R. § 292.304(a)(ii), -.304(c)(3)(i). For the Idaho Commission to apply the filed rate doctrine to Idaho utilities in other ratemaking contexts, *see e.g.* Order No. 30431 at pp. 6-7,[6] but not in the

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5 The only other logical explanation is that Langley Gulch is an excessively expensive and imprudent investment, which should not be included in Idaho Power's rate base.

6 *See NIPPC's Initial Comments*, at p. 9.

context of the availability of the published avoided cost rates, would constitute discrimination against QFs in violation of FERC's regulations and thus be subject to FERC enforcement action. *See* 16 U.S.C. § 824-3(f), (h).

Since the filing of Initial Comments, the Utilities have confirmed NIPPC's fear that the availability of published rates in the interim between December 14, 2010 and the final order is unknown. NIPPC requested that the Utilities explain the eligibility cap for published avoided cost rates after December 14, 2010, and whether the cap is different for different resources. Avista responded most succinctly by stating, "the actual level of the published avoided cost rate eligibility cap is currently an open issue to be decided by the Commission in this proceeding." *Avista's Response to NIPPC Request No. 53.* In other words, Avista does not know what the current eligibility cap is for any given QF resource. Although Idaho Power's response referenced to Order No. 31025, Idaho Power has begun filing for Commission orders "accepting or rejecting" QF contracts. *See, e.g., Application*, Case No. IPC-E-10-51, ¶ 3 (noting the purported effective date of December 14, 2010, for the Commission's yet-to-be-issued eligibility cap order). Idaho Power has likewise begun instructing developers with *fully executed contracts* that they must post thousands of dollars for network transmission upgrade studies even though according to Idaho Power "[t]he adjustment requested in this filing could affect your project's eligibility for the published avoided cost rate."

The Commission should reverse course and reject this approach as it did in the last wind moratorium in Case No. IPC-E-05-22. There, the Commission initially declared that its ruling on the Utilities' request for a reduction in the eligibility cap would be retroactively effective. But in its final order the Commission declared that the effective date of its order would be the date of the final order.

The Commission acknowledged its earlier Notice Order, but the Commission stated it was nevertheless "obliged . . . to enforce PURPA and FERC rules and regulations that require utility purchases of QF capacity and energy. . . . Mandatory PURPA resources offered under the Commission approved avoided cost methodology cannot be declined by Idaho Power[.]" Order No. 29872, at p. 9. The Commission stated "we find it reasonable to grant reconsideration and to change the date for grandfathering eligibility from July 1[, 2005], the date of our Notice, to August 4, 2005, the date of our interlocutory Order No. 29839." *Id.* at p. 11. The Commission reasoned "that until published rate eligibility was changed by Commission Order on August 4, 2005, Idaho Power had a continuing obligation under PURPA, FERC rules and the Orders of this Commission to offer to purchase QF power at the published rate and to engage in contract negotiations with eligible QFs." *Id.*

This prior approach regarding the effective date is consistent not only with the legal requirements of federal and state law, but also with Idaho's proud tradition of requiring Idaho utilities to honor the existing published rate schedules. In a seminal Idaho PURPA case, Idaho Power attempted to absolve itself of the obligation to negotiate and execute contracts containing the then-current published rates on the ground that it had requested the Commission lower the rates. The Commission extensively admonished Idaho Power, with the following order:

> Such a defiance of final ratemaking orders is unparalleled in the experience of this Commission. We remind Idaho Power Company that it is a regulated utility and that its announced Company policy in this matter makes it an outlaw--in that word's precise meaning of operating outside the law. The so-called "-200 rates" do not exist as a matter of law. They are simply a proposal put forward by Idaho Power without even a proposed effective date in a case that has not yet been heard. . . .

> *It is unheard of for a regulated utility to charge for its services at rates other than those approved by and posted at the Public Utilities Commission. This is true even though the Company has filed for new rates and believes that its old rates are inadequate or even confiscatory.* To unilaterally change rates that are charged for sales or rates that are paid for purchases is to wage a collateral attack on final Commission orders in the precise manner prohibited by Idaho Code § 61-625. Thus, the fact that on July 29, 1982, Idaho Power filed for revised avoided cost rates to be paid cogenerators and small power producers does not provide any justification for refusing to purchase power at rates that are now approved and on file.

Order No. 17796, at pp. 4-5 (emphasis added).

In this case, the Utilities each have published rates on file with an eligibility cap developed in an intensely litigated case. The Commission should not allow the Utilities to subvert the filed rate doctrine and prior Commission precedent by issuing a retroactively effective eligibility cap reduction.

C. AVISTA AND ROCKY MOUNTAIN POWER HAVE MADE NO CASE THAT THEY ARE BEING INUNDATED WITH LARGE LEVELS OF QF POWER.

Avista and Rocky Mountain Power have not even submitted evidence that they currently have substantial QF power online or that they face a significant amount of QF projects which are near execution of contracts. To the extent that Avista states QFs attempting to sell to Idaho Power or Rocky Mountain Power could wheel the power into Avista's territory, the discovery responses indicate that transmission capacity between Avista and those two utilities is currently unavailable. *See Idaho Power's Response to NIPPC Request No. 12(d)*; *Rocky Mountain Power's Response to NIPPC Request No. 12(e)*. Further, Avista has confirmed that, although many QFs have contacted Avista, it currently has no wind QFs online, and that it is essentially not concerned with non-wind and non-solar QFs aggregating their projects to obtain published rates. *Avista's Response to NIPPC Request Nos. 7 and 18.* The chart of Idaho PURPA contracts and proposals attached to Rocky Mountain Power's Initial Comments demonstrates that it has only a pittance of PURPA projects in Idaho, with only 8.3 MW online, and only an additional 43 MW under Commission-approved contract. The speculative assertion that 500 MW of QF wind projects are proposed – without supporting evidence of how far along those projects may be in the development process – is hardly a basis to eliminate the availability of published rates. This is especially so in light of Rocky Mountain Power's assertions in other regulatory contexts (discussed below) requesting cost recovery for transmission upgrades to build generating facilities in Idaho and its assertions of the need for additional wind capacity.

D. THE CURRENT, PUBLISHED, AVOIDED COST RATES ARE A FAIR APPROXIMATION OF THE UTILITIES' AVOIDED COSTS FOR A LONG TERM POWER PURCHASE AGREEMENT.

The Utilities' initial Joint Motion filed on November 5, 2010, requested a reduction of the eligibility cap during pendency of this docket solely on the grounds that Idaho Power and Rocky Mountain Power were receiving substantial requests for wind QF contracts and to "establish greater administrative control of contracts during pendency of the Commission's and parties' investigation of the issues." *Joint Petition and Joint Motion*, at p. 6. The Utilities' filing did not include any assertion that the published avoided cost rates were too high. Then, for the first time in their Initial Comments filed December 21st and 22nd, the Utilities each argued that the published avoided cost rates are too high, and do not accurately approximate their true avoided costs. NIPPC disagrees. And the Utilities' responses to discovery requests demonstrate that the current, published avoided cost rates for long term contracts are a fair approximation of "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." 16 U.S.C. § 824a-3 (d).

The starting point for estimating the real world cost of energy and capacity provided under a long term contract – and thus the adequacy of current rates generated in the SAR methodology – should be the price in recently executed contracts or contract offers, and the cost to ratepayers of the generation facilities built by the utilities. Analysis of such information demonstrates that the current 20-year, levelized, SAR rate of approximately $82/MWh, or $56.85/MWh for 2010 alone, compares favorably to other contracts and prices available to the Utilities and their ratepayers. *See* Order No. 31025.

First, the rates generated in the gas SAR and paid to QF developers appear to be lower than the actual cost to ratepayers when the utilities build or contract for the output of a gas plant. Idaho Power admits that its Langley Gulch gas plant will have a levelized cost of approximately $126/MWh. *See Idaho Power's Response to NIPPC Request No. 46(a).* Likewise, Avista acknowledges that for its Lancaster gas plant, the Commission recently approved of projected 2010 fixed costs of $20.87/MWh and energy costs of $58/MWh to $72/MWh – for a total of $78.87/MWh to $92.87/MWh for 2010, a year in which the published rate was $56.85/MWh. *Avista's Response to NIPPC Request No. 19(f).* Avista's Lancaster tolling agreement allowed for a reduction of Lancaster total price to $55.90/MWh for 2010, which even with lower than expected gas prices is still barely less than the applicable SAR rate for that year.[7] *Id.*

Idaho Power's recently approved Neal Hot Springs geothermal PPA further demonstrates

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[7] Unlike a QF resource taking the published SAR rate for a non-fueled project, these utility gas resources saddle ratepayers with a serious gas price volatility risk, as discussed below.

the reasonableness of the current published rates. That contract, as approved by the Commission on May 10, 2010, contains a price which begins at \$96/MWh in 2012, and escalates annually, resulting in a 25-year levelized price of approximately \$117.56/MWh. *See* Order No. 31087, at p. 2. Although the contract provided Idaho Power with certain benefits not provided in PURPA agreements, such as the renewable energy credits,[8] the price is far higher than the published SAR rates and demonstrates the reasonableness of the current SAR rates in a long term contract.

To the extent that Idaho Power asserts that the SAR rate is higher than the price it could obtain in a competitively bid wind contract, Idaho Power has provided no evidence in support of its claim. Indeed, Idaho Power stated that the range of bids into the 2012 request for proposals ("RFP") was between \$85/MWh and \$150/MWh. *See Idaho Power's Initial Comments*, at p. 23. Idaho Power correctly notes that the current, levelized, published, SAR rate is \$82.38/ MWh for a project that would come on-line during 2011, but failed to note that price would decrease by \$6.50/MWh for the wind integration charge and compares favorably at \$75.88/MWh to all bids into the 2012 RFP. *Id.* [9] It is impossible to understand how ratepayers are harmed by wind developers agreeing to build their projects at the lower PURPA rates instead of the higher rates

[8] The other benefits cited by the Commission included: "(1) the Company's rights to any of the project's renewable energy credits, (2) the limited ability to curtail energy, (3) the right of first offer on ownership of other site development, (4) exploration, development and construction milestone requirements and associated damages, and (5) the right to extend the terms of the contract." *Id.* NIPPC does not intend to suggest that the Neal Hot Springs contract was unreasonable, but only provides its price for comparison purposes.

[9] In Idaho Power's Response to NIPPC's Request No. 42, Idaho Power compares the 2012 RFP bids to the 2009 avoided cost rates for wind at \$89.06/MWh. But that comparison is improper and useless for purposes of this docket because the wind contracts currently submitted for Commission approval all contain the lower rate of \$75.88/MWh, and therefore all compare favorably with the costs bid into Idaho Power's most recent wind RFP. *See* Case Nos. IPC-E-10-47 to -62.

bid into the RFP.

Idaho Power's Initial Comments also improperly evaluated the reasonableness of the current SAR rates available for a long term contract by comparing them to a current Mid-Columbia price curve. *See Idaho Power's Initial Comments*, at p. 18. By doing so, Idaho Power compares apples to oranges because Idaho Power admits that "it is unlikely that Idaho Power could enter into a 20-year contract today for energy and capacity at the rates in the graph on page 18 of Idaho Power's Comments for Mid-C prices." *Idaho Power's Response to NIPPC Request No. 45(b).* This is because, as Idaho Power admits, Mid-C prices over the next 20 years could be higher or lower than those shown in Idaho Power's chart, *See id.* at *No. 45(e)*, and it would be very risky to enter into an obligation to sell power for 20 years at the currently very low Mid-C prices. Further, in the Langley Gulch proceeding, Commission Staff stated, "Relying on the market as an alternative to building new generation . . . carries greater risk and the potential for price volatility. Staff notes, as does the Company, that there are transmission constraints on imports from the Northwest that make locating new generation near its load center a prudent planning decision." Order No. 30892, at p. 14. It is interesting to note that, had Idaho Power compared the prices for its non-PURPA projects and PPAs discussed above to the low market price curve in its comments in this case, those projects would also appear to be quite uneconomical.[10] To now compare the PURPA rates to a market price curve borders on frivolous.

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[10] Indeed, Idaho Power's use of the currently low Mid-Columbia price curve as a comparison to a long term PURPA PPA rate is particularly disingenuous because in the context of analyzing wind integration costs – which decrease as market prices decrease – Idaho Power insisted on including as a component of its analysis of historic energy prices the extraordinarily high average market price of $132/MWh from 2000. *See Enernex's Idaho Power 2007 Wind Study*, Case No. IPC-E-07-03, pp. 5, 50, 85 (February 6, 2007). By doing so, Idaho Power very clearly overestimated the costs of wind integration in its study. A fair comparison of the current

Even the recently abandoned wind SAR docket further demonstrates that the gas SAR rates are not too high. Commission Staff's Wind SAR Strawman assumed that but for the QF purchase the utility would build its own wind farm, and it therefore analyzed the avoided costs as the cost to a utility to build its own wind farm. Staff stated that a 20-year levelized wind rate with a 2010 online date would be as follows for each utility for both a wind and a gas SAR:

Utility	Wind SAR	Gas SAR
Avista	\$86.31/MWh	\$79.17/MWh
Idaho Power	\$84.72/MWh	\$79.19/MWh
PacifiCorp	\$85.06/MWh	\$79.31/MWh

See Commission Staff's Wind SAR Strawman, Case No. GNR-E-09-03, at p. 12 (May 27, 2010). Even with a reduction in the wind SAR rates for the value the utility would obtain from federal tax credits, this wind SAR generated a rate that was higher than the current gas SAR prices. This wind SAR demonstrates that the gas SAR rate is not too high. This is especially so because, for a non-wind QF such as a co-generation plant which imposes no wind integration costs on the utility, the wind SAR rate would need to be increased by \$6.50/MWh to over \$90/MWh to account for the wind integration cost avoided by the utility purchase from the non-wind QF.[11]

Finally, the utilities all rely on the "dispatchability" of their own resources as a basis for

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PURPA rates to market prices over the 20-year lives of the contracts would also utilize historic prices and perhaps include that high 2000 price to demonstrate that Idaho Power may well be selling excess PURPA wind power on the open market at a substantial profit, or be utilizing it during a similar market price spike as it surely did in 2000 with QFs then online.

11 Although the parties to the wind SAR docket debated ownership of the RECs in a Wind SAR rate, Staff itself assumed that "it could be implied from these rates, that the approximate 20-year levelized value of RECs is between \$5.50 and \$7.10." *Id.* at p. 13. With that assumption, the wind SAR Strawman demonstrates that the current gas SAR rates are at least as accurate as the cost of a utility to build and operate its own wind project for delivery in Idaho.

their assertion that the published rates are too high because QF power cannot be dispatched. This argument, however, ignores that the current PURPA contracts do not compensate QFs for any right to dispatch or curtail their facilities. The Utilities admit that under an Idaho PURPA PPA they "would not compensate a QF when the QF is not delivering energy." *See, e.g., Avista's Response to NIPPC Request No. 19(b)*. In contrast, "Avista makes a payment under the Lancaster Power Purchase Agreement (tolling arrangement) when no energy is delivered. This payment provides Avista with the right to call on this capacity when it wants it." *Id.* at *No. 19(d)*. That fixed cost is approximately $20/MWh. *Id.* at *No. 19(f)*. Additionally, Idaho Power justifies the difference of $44/MWh between the cost of Langley Gulch to ratepayers and the published avoided cost rate ($126/MWh - $82/MWh = $44/MWh) on the ground that the plant is available whenever the utility needs to use it. *See Idaho Power's Response to NIPPC Request No. 46(b)*. No QF receives a flat rate payment of $20/MWh to $44/MWh at times when no energy is delivered, and the Utilities complaint about QFs' lack of dispatchability is therefore misplaced.

Further, there is no question that certain QF technologies can provide capacity on call to the utility. *See Comments in Opposition of Dynamis Energy*, at p. 2 (December 22, 2010). There is no incentive to do so, however, because the Utilities have not provided for a QF capacity payment available at times when no energy is delivered. If the Utilities wish to contract for the right to dispatch QF facilities, they should offer to provide QFs a fixed capacity payment option similar to those provided by ratepayers for Langley Gulch and the Lancaster Plant. But the Commission should not accept this "dispatchability" argument as a ground to eviscerate the availability of published rates for virtually all QF projects.

E. THE UTILITIES' INITIAL COMMENTS MISREPRESENT THE DATA REGARDING THE PROPOSED WIND QF PROJECTS AND IGNORE THE BENEFITS OF THOSE PROJECTS TO RATEPAYERS.

To justify the request for an immediate reduction in the eligibility cap, the Utilities each ignore the benefits of the wind QF projects to reach a conclusion that the inundation of wind projects will overload their systems in light load hours and impose upward pressure on rates. *See Idaho Power's Initial Comments*, at p. 19 (speculating through a series of highly questionable assumptions that market prices will be $30/MWh lower than QF contract rates, and that therefore 614 MW of wind contracts submitted for approval "equates to a rate increase of around 5 percent in the Company's PCA"). This argument, of course, ignores that all new resources will increase rates when compared to the currently low market prices, or to Idaho Power's existing generation resources. *See* Order No. 30892, at p. 31 (wherein Idaho Power acknowledged for Langley Gulch if you "just simply lay that rate base and depreciation and such onto our current rates, you get a number close to . . . six or seven percent" of rate increase, but asserted "you can't just view the rate impact in isolation."). More importantly, the Utilities' argument overlooks the benefits of these new renewable energy projects to their resource portfolios.

1. The QF wind will enable to Utilities to reduce their exposure to future coal regulation.

Idaho Power and Rocky Mountain Power both assert that "excess wind events" during light load months or hours will require them to back down their "low cost" coal resources to their minimum generation levels. According to them, "the avoided cost pricing that the QF receives should be adjusted down to reflect the Company's obligation to accept the QF's higher cost power and <u>*back down the Company's lower cost resources such as a coal plant*</u>." *Rocky Mountain Power's Initial Comments*, at p. 7 (emphasis added); *see also Idaho Power's Initial*

Comments, at pp. 16-17. This argument is absurd because coal is unlikely to be a low cost resource even a few short years from now, and the Utilities would be prudent to pursue renewable fuel resources to limit exposure to future coal regulations.

Rocky Mountain Power admits, "It is possible that PacifiCorp/RMP's coal plants could experience increased costs as a result of ongoing [Environmental Protection Agency ("EPA")] rulemaking proceedings . . . . PacifiCorp/RMP will seek recovery of such costs from its customers." *Rocky Mountain Power's Response to NIPPC Request No. 48*; *see also Idaho Power's Response to NIPPC Request No. 48.* Indeed, Rocky Mountain Power's parent company, MidAmerican Energy Holdings Company, stated in the ongoing EPA rule-making regarding coal combustion residuals ("CCRs"), that the proposed regulation of CCRs alone would "cost each facility tens of millions of dollars." *See Comments of MidAmerican Energy Holdings Company on Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule* (hereinafter "*MidAmerican Comments*"), U.S. EPA Docket ID No. EPA-HQ-RCRA-2009-0640, at p. 12 (November 19, 2010); *see also See* 75 Fed. Reg. 35,128 (June 21, 2010) (setting forth the proposed CCR regulations).

And CCRs are but one of many future regulatory hurdles that will substantially increase the price of each incremental unit of electricity generated by a coal plant. "PacifiCorp operates eleven CCR surface impoundments . . . . [and the proposed CCR regulations impose] a significant undertaking particularly considering all of the other regulatory requirements that electric generating facilities may be required to comply with in the next few years including the Clean Air Transport Rule, regional haze BART determinations and reasonable progress goals, the utility hazardous air pollutant maximum achievable control technology rulemaking, climate change-related regulatory requirements, and a potential Clean Water Act section 316(b) final rulemaking." *MidAmerican Comments*, at p. 12. EPA is therefore processing six separate regulatory changes that will increase the cost of coal-fired electricity.

Yet the Utilities provided only very limited analysis of the increased costs to their ratepayers to NIPPC in discovery. *See Rocky Mountain Power's Response to NIPPC Request No. 48* (setting forth a very high confidential cost estimate for pollution upgrades for one hazardous pollutant – mercury – at only three of its several coal plants, and similarly high estimates for the CCR rule); *see also Idaho Power's Response to NIPPC Request No. 48* (providing no cost estimates, but stating, "Idaho Power would expect to be able to include any additional capital costs associated with future regulations in its rate base, and recover any additional operating expenses incurred").

Indeed, since this PURPA docket commenced, EPA announced its plans to proceed forward with perhaps the most economically significant regulation that will affect existing coal plants. On December 23, 2010, EPA announced that it would commit to issuing proposed regulations of greenhouse gas emissions from existing power plants by July 26, 2011, and final regulations by May 26, 2012.[12] There is no doubt that greenhouse gas regulation will increase coal prices and require curtailment for Idaho Power and Rocky Mountain Power.

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[12] This rulemaking is a result of the Supreme Court's ruling in *Massachusetts v. EPA*, 549 U.S. 497 (2007), where the Court ruled that EPA has authority to regulate greenhouse gas emissions under the Clear Air Act. EPA agreed to commence this rulemaking in settlement of a Clean Air Act lawsuit brought against EPA by thirteen States and Cities, as well as individual advocacy groups. It therefore appears unlikely that EPA can abandon its rulemaking schedule. Information is available online at http://www.epa.gov/airquality/ghgsettlement.html.

Rocky Mountain Power provided a link to a study conducted by the Oregon Public Utility Commission into the cost of reducing greenhouse gas emissions 10% below 1990 levels by 2020, or 15 % below 2005 levels by 2020, and there is no reason to expect any less of a regulatory burden from the EPA rulemaking. *See* Public Utility Commission of Oregon, *Electric and Natural Gas Company Rate Impacts to Meet 2020 Greenhouse Gas Emission Reduction Goals,* (November 1, 2010), available online at http://www.oregon.gov/PUC/2020_Greenhouse_Gas_Emission_Reduction_Goals.shtml. The report indicates that PacifiCorp would have to reduce its greenhouse gas emissions in 2020 by 54%, and Idaho Power by 16%, from levels in their respective IRPs. *Id.* at p. i. PacifiCorp would meet the more stringent target by "reduc[ing] generation from its coal fired plants" and adding "a significant amount of wind power . . . , totaling 1,340 MW by 2020." *Id.* at pp. i, 7.[13] Idaho Power too would meet the goal "by curtailing coal fired generation primarily in the spring and fall months when the company typically has surplus generation capacity." *Id.* at p. 8.[14] Coal curtailment and replacement of lost generation could be necessary as soon as the EPA's rule goes into effect in May 2012.

With EPA's six rulemakings, ratepayers will pay more for coal generated power and need

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13 It is worth noting in this context that PacifiCorp recently obtained incentive transmission rate treatment from FERC for its Populus to Terminal line, in part on its asserted basis that southwestern Idaho would be a "hub," from which "power will be collected and moved in different directions." *See* 125 FERC ¶ 61,076, Docket No. EL08-75-000, ¶ 3 (October 21, 2008). PacifiCorp sought recovery also from its retail ratepayers in its 2010 Idaho general rate case on the ground that the project will facilitate the integration of potential new energy resources in Wyoming, Utah, Idaho and Oregon, and help support economic development in those states. *See* Direct Testimony of Darrell Gerrard, Case No. PAC-E-10-07, pp. 4, 8 (May 2010). This appears inconsistent with Rocky Mountain Power's aversion to Idaho PURPA projects.

14 This plan to curtail in times of surplus energy assumes that the greenhouse regulation will look only at output on an annual basis, which is far from certain with the EPA's rulemaking.

to replace energy not generated due to the necessary curtailments. Yet Rocky Mountain Power asserted in its Initial Comments in this docket –almost at the same time that it argued the opposite elsewhere regarding these future coal expenses – that the proposed wind projects are too costly in part because they will force it to scale back operation of its "low cost" coal units. Banking on coal units owned by the utility as a money saving proposition for ratepayers over wind projects under contract with independent developers is simply not reasonable. Indeed, because QF's will enable the Utilities to avoid the cost of future fossil fuel regulatory compliance associated with that incremental unit of generation provided by the QF, the avoided cost rate could be increased by an approximation of that avoided cost once the regulations are in place. *See California Public Utilities Commission*, 133 FERC ¶ 61,059, at ¶ 31 (Oct. 21, 2010) (order denying rehearing) (stating QFs may receive a *higher* avoided cost rate for providing energy and capacity that enables a utility to avoid environmental compliance costs, "if the environmental costs 'are real costs that would be incurred by utilities'"). Based on the Utilities' own statements cited herein, these future coal costs are real costs and the wind QF projects will allow the Utilities to avoid those costs.

2. The QF contracts will reduce the Utilities' exposure to future fuel price variability.

A typical QF contract contains a fixed rate for a 20-year term. "Idaho QF contracts do not allow for the QF to increase avoided cost prices in their contract in the event that QF projects' costs increase." *Rocky Mountain Power's Response to NIPPC Request No. 49.* There is therefore no opportunity for the QF taking non-fueled rates to increase the price ratepayers pay it if its fuel price increases over time. *See Avista's Response to NIPPC Request No. 47(a)*; *see also Idaho Power's Response to NIPPC Request No. 47(a)* (not directly answering the question, but nevertheless stating, "there is the risk that a QF wind project will not produce its expected or forecast amount of generation . . . . potentially resulting in additional market purchases or increased generation from other utility owned resources, which would subject the utility and its customers to market or fuel risk."). Additionally, for a QF using no fuel – such as a wind QF – a drastic increase in fuel prices is unlikely to have any impact on the QF's ability to perform because the QF has no operating fuel cost. A renewable QF project therefore provides the utility with a strong hedge against future increases in fuel costs.

In contrast, the cost to ratepayers of a typical utility built or contracted fossil fuel plant increases when the price of the fuel increases. For example, "fuel and transportation costs associated with operating the [Lancaster] plant are subject to market conditions and they will change from time to time." *Avista's Response to NIPPC Request No. 19(f)*. While those Lancaster costs were lower than expected in 2010, they could just as easily be far higher than expected in future years. And natural gas is not the only fuel subject to increases. The price to supply Idaho Power's and PacifiCorp's jointly owned Bridger coal plant increased significantly in 2010, and that cost increase was passed on directly to ratepayers. *See* Order No. 31093, at pp. 13-14 (noting that the increased cost was $63.7 million in 2010 to Idaho Power customers alone).

3. QFs pay disproportionately for interconnection and network transmission upgrades when compared to utility built resources, which provides ratepayers with system benefits while relieving them of associated costs.

Idaho Power improperly alluded to possible additional transmission costs related to QF projects without noting that ratepayers are relieved of substantial interconnection and transmission costs for a QF resource as compared to a utility-owned resource. *See Idaho Power's Initial Comments*, at p. 19.

In discovery responses, however, Idaho Power acknowledged that "PURPA QF projects are solely responsible for the interconnection costs required to interconnect their proposed projects to Idaho Power's system." *Idaho Power's Response to NIPPC Request No. 41(a).* It also admitted, "PURPA QF projects are almost always responsible for the network upgrades, or transmission upgrades, required to bring their energy from the point of interconnection with Idaho Power's system to load." *Id.* at *No. 41(b).* In some cases, Idaho Power and the ratepayers have shared in the cost of network upgrades, but even then Idaho Power and its ratepayers contributed only 25% of the cost of the needed transmission upgrades. *See id.* (discussing Order No. 32136). Under the approved methodology, the QF would "make a non-refundable 25 percent contribution in aid-of-construction ("CIAC") to support the transmission upgrades," and "an advance in aid-of construction ("AIAC") for the remaining balance of the cost of the upgrades. The AIAC will be refunded to [the QF] over time if it fully performs [on] its Firm Energy Sales Agreement with Idaho Power." *Id.* Thus, the QF pays 25% of the total cost regardless of its performance, and it obtains a refund of an additional 50% paid up front only if it performs.

In contrast, all prudently incurred interconnection and transmission costs associated with a utility-owned project will be "included in customer rates." *Id.* at *No. 41(d).* Similarly, when the federal jurisdiction applies and the Idaho Commission does not determine cost sharing, all independent developers receive a refund for the *entire* cost of network transmission upgrades required for their projects under FERC interconnection rules. "The Interconnection Customer initially funds the cost of any required Network Upgrades (i.e., Upgrades to the Transmission System at or beyond the Point of Interconnection) and it is then subsequently reimbursed for this upfront payment by the Transmission Provider." *Standardization of Small Generator Interconnection Agreements and Procedures*, FERC Order No. 2006, at ¶ 40, Docket No. RM02-12 (May 12, 2005) (addressing Small Generator Interconnection Agreements and cross referencing same rule in Order No. 2003 regarding Large Generator Interconnection Agreements).[15] Thus, under current Idaho Commission precedent, Idaho ratepayers have received a great deal from the Idaho QFs who are helping fund necessary network transmission upgrades.

F. THE COMMISSION SHOULD NOT DEPRIVE RATEPAYERS OF THE BENEFITS QF PROJECTS MADE POSSIBLE BY REGIONAL AND NATIONAL POLICIES DESIGNED TO PROMOTE THOSE RESOURCES, OR RELY UPON THE UTILTIES TO TAKE ADVANTAGE OF THOSE OPPORTUNITIES THEMSELVES.

According to Idaho Power, the "current avoided cost rates, combined with tax credits and other incentives, have created a situation where independent developers can easily justify the economics of (and finance) PURPA projects." *Idaho Power's Initial Comments*, at p. 13. "The result is that the Company's extensive IRP process, which is mandated and overseen by the Commission, is being circumvented by the current Idaho requirements of PURPA." *Id.* But Idaho Power points to no long term resources planned in the IRP process that carry as low a cost to ratepayers as the current avoided cost rates. That PURPA wind QFs are now able to build cost-effective projects in Idaho is a result of the many years of sweat equity invested by independent developers in wind studies, securing wind leases, and other time-consuming and

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15 FERC has argued in court successfully in defense of sharing of transmission costs "that its policy has been that all transmission customers must share the costs of network upgrades because the integrated transmission grid is a cohesive network, and the upgrades benefit *all* users, not just the newly interconnecting generator." *Energy Servs., Inc. v. FERC*, 319 F.3d 536, 539, 544 (D.C. Cir. 2003) (emphasis in original).

costly development efforts. It is a risky and often unrewarded enterprise, and one that is entitled to PURPA's mandatory purchase requirement at the utility's avoided cost, regardless of the costs to the developer.

PURPA's mandatory purchase provisions require utilities to purchase QF output at "the cost to the electric utility of the electric energy, which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." *See California Public Utilities Commission*, 133 FERC ¶ 61,059, at ¶ 29 (quoting 16 U.S.C. § 824a-3(d)). The focus is on calculating the cost to the utility of energy alternatives to the QF energy. The current gas SAR methodology does just that. But the Utilities' filings to date improperly focus on the cost to the QF to build their resource. *See Idaho Power's Initial Comment*, at p. 10 (stating that the QFs are gaining "double recovery windfall" through RECs and tax credits).

If the utilities want to take advantage of the available tax credits and REC markets, they should endeavor to build their own renewable projects. But perhaps it is not appropriate for an investor-owned utility to be engaged in the risky business of developing a wind project. Avista received preferential construction work in progress ("CWIP") ratemaking treatment for its Reardon wind project in 2008, at which time it informed the Commission construction would begin in 2011. *See* Order No. 30611, at p. 2 (stating "Avista believe[d] it [wa]s cost effective and prudent to secure land rights and equipment now, even though actual construction will not begin until 2011"). The Commission approved of CWIP for Reardon, which allows Avista, unlike a QF wind developer, to accrue a carrying charge at its authorized rate of return before the project is online, and indeed before construction has even begun. *Id.* To date, Avista has invested \$3.7 million in its Reardon wind project. *See Avista's Response to NIPPC Request No. 21(b)'.*

But the Reardon project "is not under construction and will not be online in 2012," so Avista will need to revaluate its options as a renewable resource requirement in Washington's RPS statute approaches in 2016. *Id.* at *No. 21(a).* If Reardon is ever constructed, "it would likely be in the 2014-2016 timeframe." *Id.* at *No. 21(d).* Avista purports to not possess \$/MWh cost estimates of Reardon. *Id.* So one must presume – and Avista will surely have to prove at some point – that the all-in costs for Reardon with CWIP are cost-effective against the \$76/MWh rate it would pay to the wind QFs knocking on its door in this case. Avista also appears to assert that its ratepayers will not suffer any economic damage from the construction delay, but on this point, Avista's treatment of its own resource is inconsistent with its requirement that QFs post \$45/kilowatt of nameplate capacity as delay default liquidated damages security to Avista. *Compare id.* at *No. 21(b)* (stating that the delay in the online date projected in the IRP for Reardon is immaterial because the IRP process "does not commit the Company to build any project. Damages are inapplicable."), *with id.* at *No. 54(a)* (stating, "Avista could suffer substantial costs if a PURPA resource that it has a contract with does not achieve commercial operation within the time provided in the contract. . . . . for example, anytime a PURPA contract is executed, Avista reflects the contract in its Loads and Resources tabulations and IRP work."). Avista's preferential and off-handed treatment of the delay event in its own wind project's on line date vis a vis how it treats delay for PURPA projects is a blatant example of that utility's discriminatory treatment of QFs.

In any event, Avista's apparent struggle with Reardon, even with preferential CWIP financial benefits, demonstrates that developing a wind farm is not easy, and the Commission should not impose additional hurdles for the QF developers whose projects are at risk in this docket. A QF developer will obviously need to find a way to build and operate its project at a cost that is lower than the avoided cost rate it will be paid for the output. Otherwise, the QF would go out of business. That QFs are able to take advantage of federal tax credits, Idaho sales tax exemptions, and neighboring states' RPS standards to build and operate projects profitably is simply not a justification to lower the avoided cost rates through the IRP methodology or otherwise.

The Utilities have demonstrated no reason to deprive ratepayers of the benefits of long-term contracts for renewable resources which carry no fuel cost or regulatory risk to ratepayers. QFs' ability to provide energy and capacity at the Utilities' avoided costs and still turn a profit only demonstrates that recent federal and state policies to promote renewable energy are working. It would be illegal and improper for this Commission to undo the effect of those policies and undermine the investment-backed expectation of QF developers by granting the Utilities' request to retroactively eviscerate the published rate schedule and require all QFs to proceed under the IRP methodology effective December 14, 2010.

CONCLUSION

The assault on Idaho's PURPA implementation in this docket is particularly troubling in light of Idaho Power's admission in Response to NIPPC' Request No. 43, that Idaho Power, through an affiliate named IdaWest Energy, owns a 49% interest in four PURPA projects totaling over 33 MW of capacity currently selling their output to Idaho Power. Thus, Idaho's proud PURPA tradition under assault by the utilities in this docket even includes utility-owned

PURPA projects.

For all of 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. NIPPC further requests that the Commission make any reduction in the cap effective on the date of the Commission's order reducing the cap, not on the retroactive and arbitrarily-determined date of December 14, 2010.

In closing, it may be helpful to remind the Commission of its goals when it was in the early days of implementing PURPA. Such goals are as valid today as they were in 1982. The Commission stated, in Order No. 17796, pp. 17-18:

> Given this background, the Company has the ability to serve as a catalyst for economic growth in the state. Rather than building costly plants out-of-state, it could harness the power of Idaho streams, canals and irrigation ditches in cooperation with farmers, ranchers, canal companies and irrigation districts. It could enter a partnership with the state's depressed forest products industry and its food processing industry to put waste heat from those industries to work. It could pump life into local municipal and county governments by aiding construction of municipal waste incineration facilities that produce electricity and by increasing the employment and tax base from diversified cogeneration and small power projects located throughout the state. The state cries out for such vision and for the leadership to carry it out. Instead, the management of Idaho Power is mired down in an expensive war of attrition against co-generators and small power producers trying to turn back the clock to a time when the Company had absolute control over the production of electricity in its service territory.

Respectfully submitted this 19th day of January, 2011.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 12th day of January, 2011, a true and correct copy of the within and foregoing **NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S REPLY COMMENTS** was served as shown to the following parties:

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Signed ______________________
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