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IDAHO PUBLIC UTILITIES COMMISSION

February 28, 2011

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 West Washington
Boise ID 83702

GNR

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

Dear Ms. Jewell:

We are enclosing an Original and seven (7) copies of the PETITION FOR RECONSIDERATION OF THE NORTHWEST AND INDEPENDENT POWER PRODUCERS COALITION for filing 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 and Greg Adams

encl.

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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** **PETITION FOR RECONSIDERATION OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION**

COMES NOW, the Northwest and Intermountain Power Producers Coalition ("NIPPC") and pursuant to Idaho Administrative Rules ("IDAPA") 31.01.01.331, hereby respectfully requests that the Idaho Public Utilities Commission (the "Commission") reconsider Order No. 32176. Without waiving any arguments raised in its prior filings in this docket, NIPPC respectfully requests that the Commission (1) take official notice of the documents and records cited by NIPPC; (2) hold an evidentiary hearing on the issues addressed in Order No. 32176; (3)

order the investor-owned utilities in Idaho to immediately implement changes to the Integrated Resource Plan Methodology ("IRP Methodology") for calculating avoided cost rates such that it compensates qualifying facilities for the utilities' *full* avoided costs; and (4) re-instate the 10 average mega-watt ("aMW") published avoided cost rate eligibility cap for wind and solar projects.

INTRODUCTION[1]

On Friday, November 5, 2010, Idaho Power Company ("Idaho Power"), Avista Corporation ("Avista") and PacifiCorp, DBA Rocky Mountain Power ("Rocky Mountain" or collectively "the Utilities") lodged a Joint Motion ("Motion") and Joint Petition ("Petition" or collectively the "Pleading") with the Commission. 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"). 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.

In response, in Order No. 32131, the Commission 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:

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[1] NIPPC incorporates by reference all of its prior filings in this docket, and hereby requests reconsideration of each argument raised by NIPPC in its opposition to the reduction in the published avoided cost rate eligibility cap.

> 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 (emphasis added).

But the Commission's procedural order in this case required only "comments in support or opposition" followed by an oral argument on January 27, 2011. *Id.* at p. 6. 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." *Id.* at p. 5. After close of the QF eligibility cap phase of this docket, the Commission stated it will move to a new phase of the case in order to explore the other PURPA issues raised in the Joint Petition.

The Commission accepted two rounds of comments and held oral argument. Rocky Mountain Power filed testimony of its proffered witness, Bruce Griswold, but withdrew the testimony in response to NIPPC's objection to accepting testimony from only one party and providing no opportunity for cross examination. Tr., at p. 11; *NIPPC's Motion to Strike the Direct Testimony of Bruce Griswold or in the Alternative to Amend Schedule* (January 21, 2011); Order No. 32176, at p. 4. At oral argument, NIPPC requested to properly submit information produced in discovery into the record, Tr., at pp. 6-7, 11, and to provide the testimony of

NIPPC's witness regarding the flaws of the IRP Methodology. *See id.* at pp. 6-7, 48, 96-99. But the Commission did not allow NIPPC to establish an evidentiary record. *Id.* The record in this docket therefore contains no evidence whatsoever.

Then, on February 7, 2011, the Commission issued Order No. 32176, wherein it granted the Utilities' request to "temporarily" reduce the eligibility cap to 100 kw for wind and solar QF, but rejected their request to reduce the cap from 10 aMW as to all other QF resource types. *See* Order No. 32176, at pp. 11-12. The Commission rejected NIPPC's request for an evidentiary hearing, made in NIPPC's Initial Comments and Reply Comments, apparently on the ground that the Commission was only rendering policy determinations. *Id.* at p. 4. The Commission also rejected NIPPC's request, made at oral argument, that the Commission take official notice of several public records and filings in proceedings before the Commission, other regulatory agencies, and a federal court proceeding. *Id.* at pp. 4-5. The Commission justified the reduction in the eligibility cap for wind and solar projects on the ground that those projects will be able to secure contracts with avoided cost rates calculated under the IRP Methodology. *Id.* at pp. 8-9.

ARGUMENT

A. The Commission should take official notice of filings cited by NIPPC.

At oral argument NIPPC requested, pursuant to IDAPA 31.01.01.263, that the Commission take official notice of several filings and orders in Commission cases and Federal Energy Regulatory Commission ("FERC") proceedings, as well as three items related to coal costs cited in NIPPC's Reply Comments. Tr., at pp. 8-10. NIPPC distributed to each of the parties and the Commissioners a formal request for official notice containing a list of the Commission and FERC filings and orders for which it requested official notice. Commissioner

Smith stated:

> ***I think your passing this out gives people notice of what you want us to take notice of*** and certainly we can take notice of our own orders and those of any other regulatory agency, state or federal, matters of common knowledge, technical, financial or scientific facts, matters judicially noticeable and data contained in periodic reports of regulated utilities filed with the Commission or federal agencies. *So as long as they fall in one of those categories, there's no problem with us taking notice.*
>
> Tr., at p. 10 (emphasis added).

No party voiced any objection to official notice of NIPPC's listed Commission and FERC documents and orders, or objected to Commissioner Smith's statement that the list provided the parties with adequate notice. NIPPC therefore assumed the Commission was proceeding under the provision of Rule 263, whereby official notice takes place if "agreed by the parties and approved by the presiding officer," rather than the provision requiring the party requesting notice to submit each one of the documents to the Commission and the parties.

In Order No. 32176, however, the Commission rejected NIPPC's request for official notice of all listed documents except for the Commission's own "notices and orders," on the purported basis that the "Commission acknowledged official notice of its own notices and orders," but apparently no others. Order No. 32176, at p. 5. As is plainly obvious from the above-quoted text, however, Commissioner Smith made no distinction between the Commission's willingness to acknowledge its own notices and orders and those of other regulatory agencies. At a minimum, therefore, the Commission should reconsider its decision, and take official notice of the FERC orders.

Order No. 32176 also stated that the "majority of the 'filings, testimony and exhibits from the 24 PUC dockets are not documents or information subject to official notice." *Id.* But filings in the Commission dockets are judicially noticeable, and therefore fall within the confines of Rule 263. *See* Idaho Rule of Evidence 201. A trial court may take judicial notice of records in cases before the trial court, and there is no reason this Commission may not do the same for records in its own proceedings. *Larson v. State,* 91 Idaho 908, 909, 435 P.2d 248, 249 (1967). Denying official notice under these circumstances is particularly unfair because "documents generally should be placed in evidence through the ordinary avenues specified by the rules of evidence. This is done by laying an appropriate foundation to demonstrate the documents' authenticity and relevance." *Newman v. State*, 149 Idaho 225, 227, 233 P.3d 156, 158 (Ct. App. 2010). If necessary, NIPPC intended to admit its documents through the witness it offered, but the Commission rejected NIPPC's request to call its witness.

NIPPC therefore respectfully requests that the Commission take official notice of all items cited in the filing provided by NIPPC at oral argument, as well as the following items regarding coal costs, which NIPPC intended to submit into evidence through its witness, and are readily available:

(1) Settlement Agreement in *State of New York, et al. v. EPA*, No. 06-1322, before the United States Circuit Court of Appeals for the District of Columbia, regarding initiation of an EPA rulemaking on regulation of greenhouse gas emissions at existing electricity generating units; available at http://www.epa.gov/airquality/pdfs/boilerghgsettlement.pdf .

(2) 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.

(3) *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, U.S. EPA Docket ID No. EPA-HQ-RCRA-2009-0640 (November 19, 2010).

B. The Commission should hold an evidentiary hearing.

NIPPC has repeatedly requested an opportunity to present evidence in support of its opposition to the reduction in the eligibility cap. *See NIPPC's Initial Comments*, pp. 1, 12-13; *NIPPC's Reply Comments*, at pp. 1-2; Tr. a pp. 6-7, 48, 96-99.[2] The Commission denied NIPPC's request in Order No. 32176. "The Commission finds that the parties' positions have been adequately presented through initial comments, reply comments and oral argument, and that a technical hearing is not necessary to resolve the question of whether the eligibility cap should be reduced." Order No. 32176, at p. 4. "We find that the comments and oral argument provide sufficient information to resolve the *policy question* of temporarily reducing the eligibility cap." *Id.* (emphasis added). NIPPC is not the only party that sought to introduce evidence through a witness. Both PacifiCorp and Avista attempted to present factual assertions of their expert witnesses. Although PacifiCorp and Avista appear to have backed down from their initial offer of witnesses in response to NIPPC's attempt to provide its own evidence, the utilities' initial requests to provide factual assertions from their experts further demonstrates the highly factual nature of the issues before the Commission. Because the Commission's decision was necessarily based on factual findings, the Commission must hold an evidentiary hearing.

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[2] NIPPC notes the Commission stated in Order No. 32176, at p. 4, that at oral argument NIPPC "referenced the need for a technical hearing, but did not renew [its] Motion" for an evidentiary hearing. There is no requirement that a party "renew" a motion at an evidentiary hearing. NIPPC has very clearly advocated with each filing in this docket, and at oral argument, that the Commission must consider evidence to properly address the eligibility cap issue. NIPPC never waived that request, and again adamantly asserts in this petition that the Commission must hold an evidentiary hearing.

"The procedure chosen by the Commission must of course give the parties fair notice of exactly what the Commission proposes to do, together with an opportunity to comment, to object, and to make written submissions; and ***the final order of the Commission must be based upon substantial evidence***." *Intermountain Gas Co. v. Idaho Public Utilities Commission*, 97 Idaho 113, 129, 540 P.2d 775, 791 (1975) (emphasis added) (quoting *American Public Gas Association v. Federal Power Commission,* 498 F.2d 718 (D.C. Cir. 1974)). "Due process requires that a party to contested proceedings before the commission must be afforded a full opportunity to meet the issues." *Id.* (quoting *Washington Water Power Co. v. Idaho Public Utilities Commission,* 84 Idaho 341, 372 P.2d 409 (1962)).

The parties made factual allegations in the filings in this docket, which the Commission specifically noted in Order No. 32176. The Commission noted, "The utilities argue that the number of QFs currently requesting contracts under the published 10 aMW avoided cost rate is excessive and the utilities' ability to continue to accept the QF energy without negatively impacting the electric system and the utilities' customers is at risk." Order No. 32176, at p. 6. "The Intervenors generally contend that lowering the threshold is an imposition on legally permissible QF projects that cannot absorb the costs of negotiating with a utility and the increased difficulty of obtaining financing created by the uncertainty of the payments they will receive under PURPA contracts negotiated through use of the Integrated Resource Plan (IRP) Methodology." *Id.* at p. 7. "NIPPC maintains that a reduction in the published avoided cost rate eligibility cap is not warranted for any resource because the utilities have not demonstrated that the published avoided cost rate is too high." *Id.* "Staff emphasizes that, '(w)hen large QFs are added to a utility's renewable portfolio, but the QFs disaggregate in order to qualify for the published rate, the avoided cost paid to the QF becomes inaccurate, because under the published rate methodology, there's no mechanism to reflect the utility's reduced avoided cost.'" *Id.* at p. 8 (quoting Tr., at p. 88).

The issues in dispute are therefore whether the Intervenors or the Staff/Utilities are correct regarding the accuracy of the published rates and the IRP Methodology rates, as well as the impact on the each of the Utilities' system of the amount of QFs requesting contracts at this time. Those are purely factual questions that must be decided before the Commission can render any policy determination.

Thus, the Commission made factual determinations in Order No. 32176. "Based upon the record, the Commission finds that a convincing case has been made to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW for wind and solar only[.]" Order No. 32176, at p. 9. "The purpose, . . . of distinguishing between small and large QFs with the application of the IRP methodology for large QF projects is to more precisely value the energy being delivered." *Id.* at p. 10. "We believe that the IRP Methodology appropriately assesses when the QF is capable of delivering its resources against when the utility is most in need of such resources. ***The resultant pricing is reflective of the value of QF energy to the utility***." *Id.* That is simply not a matter of policy. If the Commission did not make factual determinations, there would be no basis for it to decide, over NIPPC's objection, that the IRP Methodology more accurately reflects a larger-sized QF's production and capacity than the surrogate resource methodology. Thus, the Commission's order is indefensible without at least some evidence supporting the relief granted to the Utilities.

In *Intermountain Gas Co.*, the Court reversed the Commission because "Intermountain did not have an opportunity to meet the issue of whether the continuation of its retail sales business was in the public interest and thus the order denied it due process." *Intermountain Gas Co.*, 97 Idaho at 129, 540 P.2d at 791. Likewise, here, NIPPC did not have the opportunity to meet the issue of whether the IRP Methodology currently implemented by the Utilities actually calculates the utilities' *full* avoided costs. NIPPC offered the testimony of its witness on that matter, and the Commission rejected the request, accepting no evidence whatsoever on the issue. Nor did NIPPC have the opportunity to fully challenge the Utilities' assertion that system reliability concerns and excessively high published avoided cost rates warranted a reduction in the eligibility cap. These are factual matters, not a policy determination upon which the Commission may render a decision based solely upon the arguments of lawyers. The Commission should accept evidence and reconsider its factual findings.

C. The Commission should reconsider its "findings" relative to the accuracy of the IRP Methodology in setting avoided cost rates for larger projects because the IRP Methodology violates Federal Law by dramatically understating actual avoided costs.

NIPPC commented extensively on the shortcomings in the IRP Methodology in its Reply Comments. *See NIPPC's Reply Comments,* pp. 5-11. NIPPC argued that the IRP Methodology fails to adequately implement eight distinct provisions of FERC's implementing rules for determining avoided cost rates. These eight distinct provisions require that the avoided cost rates "shall, to the extent practicable," take into account the following factors: (1) reliability, (2) contract terms, (3) ability to schedule outages, (4) ability to provide service in emergencies, (5) contribution to the system in the aggregate with other QFs, (6) contribution to savings due to shorter construction times, (7) ability to allow the utility to avoid fossil fuel risk, and (8) ability to allow the utility to avoid line losses. *See id.* at pp. 5-8 (citing 18 C.F.R. § 292.304(e)). The IRP Methodology fails to even attempt to take each of these eight factors into account, and therefore violates FERC's guidelines.

In addition to pointing out that the IRP Methodology fails to comply with these provisions in calculating avoided cost rates, NIPPC proved that it produces wildly inaccurate results. NIPPC asked Idaho Power to run its AURORA model for the Langley Gulch plant as if it were operated as a QF. As noted on page 11 of NIPPC's Reply Comments, the results of that exercise demonstrated that the IRP Methodology actually understated avoided costs rates by almost one third.[3]

In its Order, the Commission did not address any of NIPPC's assertions. Instead, the Commission merely relied on an unsubstantiated "belief" – supported only by a record completely devoid of evidence -- that the IPR Methodology is both a legally and factually sound vehicle for insuring that the State of Idaho is in full compliance with PURPA. The Commission stated, "We believe that the IPR Methodology appropriately addresses when the QF is capable of delivering its resources against when the utility is most in need of such resources." Order No. 32176, p. 10. Thus, based on that belief: "The resultant pricing is reflective of the value of QF energy to the utility," and, "Based on the foregoing, the Commission temporarily reduces the eligibility cap for published avoided cost rates from 10 aMW to 100 kW for wind and solar resources only, effective December 14, 2011." *Id.* It is nothing short of arbitrary to base such a

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3 "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." *NIPPC Reply Comments*, at p. 11.

sweeping and fact-based decision on a mere "belief" when faced with compelling arguments that the "belief" may, in fact, be in error, and when possessing no evidence that the belief is correct.

The question of the ability of AURORA and the other power supply models to accurately estimate avoided cost rates was discussed at length during oral argument. No less than three parties attempted to produce a witness to help the Commission come to a complete understanding of the issues. NIPPC offered Dr. Don Reading to explain the fact that the AURORA model fails to account for avoided capacity costs. Tr. at pp. 6-7, 48, 96-99. NIPPC has attached to this petition, as Attachment 1, a White Paper by Dr. Reading, in which he identified the three methodologies commonly used for setting avoided cost rates in various jurisdictions around the country, including Idaho. Dr. Reading demonstrates that the IRP methodology, as currently implemented, simply fails to account for capacity. Indeed, the Commission in its final order in this docket makes clear that it is only concerned with the value of energy and not capacity: "The resultant pricing is reflective of the value of QF *energy* to the utility." Order No. 31276, at p. 10 (emphasis provided).

Using information taken directly from Idaho Power's IRP process Dr. Reading demonstrated that the IRP Methodology, when used for setting avoided cost rates does not even calculate avoided costs consistent with how the utilities actually calculate the cost of new resources in their own IRP processes. This flaw highlights the black box nature of the IRP Methodology. The Utilities have not provided enough data for QFs to properly vet the individually provided results, and are hence in violation of the 18 C.F.R. 292.302(b) by failing to provide for public inspection of basic system cost data listed in the regulation.

The reason "disaggregation" ever even began occurring is that the IRP Methodology, as currently implemented, provides a rate that is a gross underestimate of the true avoided costs. *See* Tr., at p. 49. As the comments of counsel for Cedar Creek Wind demonstrated, the utilities will not provide a developer with a fair and accurate avoided cost rate through the IRP Methodology. *See id.* at pp. 55-57. That QF developer requested an IRP Methodology rate in good faith, and, after three months of waiting, Rocky Mountain Power provided it with an unbelievably low calculation of $37 per MWh. *Id.*; *see also Affidavit of Dana Zentz*, Case No. PAC-E-11-01 (Jan. 26, 2011). If the rates for the IRP Methodology were accurate and verifiable to the QFs, there would be no need to disaggregate an otherwise larger project into smaller projects to obtain the fair rate at which the project would be financially viable.

Federal law requires the utilities to contract with each QF at the *full* avoided cost rates. 16 U.S.C. § 824a-3(b), (d); 18 C.F.R. § 292.304(a), (b); *see also Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978*, 45 Fed. Reg. 12,214, 12,222-12,223 (Feb. 25, 1980) (promulgating avoided cost regulations and directly rejecting proposals to provide QFs with rates of less than the full avoided cost). Any QF using a renewable fuel source up to 80 MW in size is a "small power production facility" entitled to a contract at the utility's full avoided cost rate under FERC's rules. 16 U.S.C. § 796(17)(A); 18 C.F.R. § 292.204.

It is the blatant inaccuracies and black-box nature of the IRP Methodology that has led QF developers to find ways to act within the existing regulatory structure to obtain the published rate which more accurately reflects the Utilities' *full* avoided costs. The published rate methodology has been thoroughly litigated throughout the years, and is currently a very sophisticated pricing mechanism that takes into account all components of the Utilities' actual avoided costs. For example, it includes a discount for wind integration, and discounted payments to QFs at times of the year and day when the value of the output is less to the Utilities. Requiring wind and solar QFs to resort to the IRP Methodology on account of the "disaggregation" problem is in violation of PURPA and FERC's implementing regulations because, unlike the surrogate resource methodology used for published rates, the IRP Methodology is not designed to provide QFs with the *full* avoided costs.

D. The Commission should re-instate the 10 aMW published avoided cost rate eligibility cap for wind and solar projects because failure to do so constitutes a failure to implement PURPA's mandatory purchase obligation at each utility's *full* avoided costs.

As discussed above, PURPA requires the utilities to contract with each QF at the *full* avoided cost rates. 16 U.S.C. § 824a-3(b), (d); 18 C.F.R. § 292.304(a), (b). If a state utility commission does not require the utilities within its jurisdiction to pay the full avoided costs for QF output, that state commission would be in violation of FERC's rules and subject to FERC enforcement action, or a federal court challenge to its implementation of PURPA. *See* 16 U.S.C. § 824-3(f), (h). Because the IRP Methodology, as currently implemented, produces rates below the *full* avoided cost rates, the Commission should reconsider its decision and raise the eligibility cap to 10 aMW so that it will be properly implementing PURPA for at least some larger wind and solar QFs.

E. The Commission misconstrued NIPPC's legal position.

In Order No. 32176, the Commission stated, "Contrary to NIPPC's assertions, FERC rules insist that rates for purchases from QFs be just and reasonable to *ratepayers* and in the public interest – not in the interest of the QFs." Order No. 32176, at p. 10. But NIPPC did not assert that FERC rules insist that rates for purchases be in the "interest of the QFs." NIPPC merely cited the U.S. Supreme Court's findings with regard to Congress's reason for enacting PURPA's mandatory purchase provisions. *See NIPPC's Initial Comments*, at p. 6. The Supreme Court found:

> Traditional electric utilities were reluctant to purchase power from, and sell power to, the nontraditional facilities. 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.
>
> *FERC v. Mississippi,* 465 U.S. 742, 750-51, 102 S.Ct. 2126, 2132-2133, 72 L.Ed.2d 532 (1982) (emphasis added) (citation omitted).

While not disagreeing that avoided cost rates should, indeed, be just and reasonable, NIPPC would add that this Commission also has an obligation to implement PURPA in such a manner as to actually "encourage cogeneration and small power production" in spite of the "reluctance" from "Traditional electric utilities to contract for such power."

F. An evidentiary hearing is necessary due to Idaho Power's late admission that AURORA is incapable of accurately calculating avoided cost rates for QF projects smaller than two megawatts.

In its Reply Comments, filed January 19, 2011, Idaho Power admitted that AURORA is incapable of accurately calculating even an energy component of an avoided cost rate for projects smaller that 2 MW:

> [I]n researching the AURORA modeling capabilities, the software provider has advised that there may be some issues with the software producing dependable results for projects that are less that 2 MW. One of the reasons being that the pricing in the IRP-based methodology is a result of subtracting the base model results (that

> do not include the proposed project) from the model results, including the proposed project. If the project is small enough that it does not trigger changes in the base model operations, i.e., it is lost in the rounding to MWs or MWhs, then the base model results could be identical to the modeled results that include the project. This would result in an AURORA pricing of zero.
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> *Idaho Power Reply Comments*, at p. 13.

Idaho Power's counsel tried to retract this remarkable revelation during oral argument, only a few days later on January 27, 2011, by stating that:

> However, since the time, since January 19th at the time when we filed our reply comments, obviously, we've been working on this issue, we consulted with Avista and found out that Avista routinely runs their AURORA modeling for 100 kilowatt projects at part of their IRP process. Also the Company's analysts also ran several modelings at 100 kilowatt levels and the Company is confident that the modeling does result in accurate and usable results for projects smaller than two megawatts. . . .
>
> Tr., at pp. 18-19.

The flip flop between January 19 when Idaho Power filed its Reply Comments and January 27, the date of the oral argument is remarkable and less than credible. This is especially true since NIPPC understands that it literally takes several days for a single AURORA model to be run. Nevertheless, Idaho Power's counsel asserted that "Idaho Power personnel ran test models through the weekend." Tr., at p. 20. It is implausible to argue the company had sufficient time to conduct a thorough investigation into AUORA's ability to accurately estimate avoided cost rates for projects smaller than two megawatts. Standing alone, these discrepancies are sufficiently compelling such that the Commission must deny the Utilities request to reduce the eligibility cap pending a full evidentiary hearing into the infirmities inherent in the IRP Methodology in estimating avoided cost rates. There is no question that by doing otherwise, the

Commission would be completely failing to implement PURPA for the smallest QFs now required to use the IRP Methodology.

CONCLUSION

Wherefore, NIPPC respectfully requests this Commission issue its order granting reconsideration of Order No. 32176 by: (1) taking official notice of the documents and records cited by NIPPC during oral argument and in this petition; (2) holding an evidentiary hearing on the issues addressed in Order No. 32176; (3) requiring the Utilities to immediately implement changes to the IRP Methodology for calculating avoided cost rates such that they compensate qualifying facilities for the Utilities' full avoided costs; and (4) re-instate the ten average megawatt published avoided cost rate eligibility cap for wind and solar projects.

Respectfully submitted this 28th day of February, 2011.

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 28th day of February, 2011, a true and correct copy of the within and foregoing **PETITION FOR RECONSIDERATION OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION** was served as shown to the following parties:

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GNR-E-10-04

NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

PETITION FOR RECONSIDERATION

ATTACHMENT 1

Dr. Don Reading's White Paper

Dr. Don Reading

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NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

WHITE PAPER

IMPLEMENTATION OF THE IRP METHODOLOGY FOR CALCULATING AVOIDED COST RATES IN IDAHO

Introduction

This White Paper, prepared on behalf of the Northwest and Intermountain Power Producers Coalition ("NIPPC") by Dr. Don Reading,[1] reviews and critiques the Idaho utilities' (Avista, Idaho Power Company, and Rocky Mountain Power) and Commission Staff's proposed "IRP Methodology" for determining a utility's avoided cost for PURPA projects in Idaho having an output greater than 100 kilowatts.

Implementation of the IRP methodology in the manner recommended by the utilities and the Commission Staff will yield an estimate of variable running costs for a utility, not the utility's entire avoided cost. The models used by the utilities (AURORA or PRiSM for Avista, AURORA for Idaho Power, and Grid for PacifiCorp)[2] are commonly known as "power supply" models and produce estimates of the variable running costs to the utility. The power supply models are run first without and then including, at zero cost, the particular generating facility being examined.[3]

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1 Dr. Don Reading's curriculum vitae is Attachment 1 to his White Paper.

2 Comments of the Commission Staff, GNR-E-10-04, at p. 4. Although Staff stated Avista would use the AURORA model, Avista stated it may also use the PRiSM model. Avista's Response to NIPPC Production Request No. 23(a), GNR-E-10-04.

3 Idaho Power Company's Response to NIPPC Production Request No. 46(f), GNR-E-10-04.

The differing costs between the two runs are divided by the facility's expected output to yield a per MWh value. This method produces the utilities' variable running costs. In order to determine full avoided costs, the capital components of the facility should be included. The public record indicates the values advocated by the utilities and Commission Staff do not produce full avoided cost for a utility in compliance with the Commission's approved method.

Standard Methods for Finding Avoided Cost

State public utility commissions have used three basic approaches for determining avoided costs since the enactment of PURPA in 1978. Various states have employed various incarnations of these three basic approaches in finding avoided costs for their jurisdictions. The three methods are: 1) the Peaker Method, 2) the Proxy Method, and the 3) Differential Revenue Requirement Method.[4]

When using the Peaker Method, the utility's power supply model is run with and without the given facility, at zero cost, to produce variable costs. Then, the capital costs of a peaking unit are added to find full avoided costs.

Under the Proxy Method (which is currently used in Idaho for published rates), the capital costs of the proxy unit are included, along with operation and maintenance expenses, as part of the calculations to find the utility's avoided cost.

The Differential Revenue Requirement Method calculates the utility's total generation costs (or revenue requirement) with, and without, the proposed facility. The method first uses an expansion plan model to generate expansion plans with and without the proposed facility. The method then uses the two different expansion plans as inputs to a financial planning model to produce the utility's revenue requirement with and without the proposed facility's output provided as free energy. That financial model would include items such as interest costs, taxes, allowed rate of return on the change in rate base and capital, and other "rate case" inputs for the facility. The difference in the present value of the revenue requirement is the avoided revenue requirement component and is, in theory, the utility's full avoided cost, including avoided energy and capacity costs, as well as taxes and other cost factors.

It is important to note that all three of these basic and accepted methods include the capital cost of the generating unit being examined.

4 Edison Electric Institute, *PURPA: Making the Sequel Better than the Original* (Dec. 2006); National Economic Research Associates, Inc., *The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey* (Jan. 1992); National Economic Research Associates, Inc., *How to Quantify Marginal Costs: Topic 4* (March, 1977).

The Commission accepted the Differential Revenue Requirement Method for calculating the utilities'avoided costs for QF's larger than 10 MW in Case No. IPC-E-95-9. The Commission approved the Stipulation in that case that was signed by the three utilities, Commission Staff, and Rosebud Enterprises, Inc. Although the other parties in that case chose not to sign the Stipulation, they did not oppose the methodology. Attached to Commission Staff witness Sterling's Direct Testimony filed in that case was Exhibit 101 that contained Staff's proposed avoided cost methodology that was accepted by the Commission. This approach is the IRP Methodology.

Althgough the parties called it the IRP methodology. the essence of Staff's methodology actually employs the Differential Revenue Requirement Method described above. This methodology compares the present value of the revenue requirements (PVRR) of the base case with one that includes the utilities system including the QF. Items 6 and 7 of the Stipulation states,

> 6. Finally, the present value of the QF project avoided cost is calculated by subtracting the PVRR of the modified plan, with the costs of the QF set to zero, from the PVRR of the base case resource plan.
>
> 7. Rates for capacity and energy from the QF project can then be developed for which, on a present value basis, the expected payments to the QF are equal to the project's avoided cost over the life of the contract.[5]

Note that item 7 states that avoided cost rate for a QF are found by using both capacity and energy. The end result is that Idaho has two methods for calculating avoided cost, the Proxy method for smaller projects, and the Differential Revenue Requirement Method for larger projects.

<u>IRP Methodology as Advocated by the Utilities and Commission Staff</u>

The Commission Staff indicates the "IRP Methodology" has been utilized in only two PURPA contracts since PURPA was first implemented in Idaho.[6] One of these is the Rockland Wind Project. The Commission Order approving that contract states,

> This model provides strictly an energy price based upon the estimated generation from this Facility being available to meet Idaho Power s customers' energy needs. This AURORA energy price contains no value for RECs or other items of value identified within the Agreement. The energy price identified by the AURORA run, including a discount of $6.50 per megawatt-hour (MWh) for wind

5 Direct Testimony of Rick Sterling, IPC-E-95-09, Exhibit 101, p. 8.

6 Comments of the Commission Staff, GNR-E-10-04, p. 4.

integration, was a levelized price of $56.21. In comparison, the published avoided cost levelized price for a 10 average MW or less PURPA wind project with a planned on-line year of 2011 is $75.88 per MWh.[7]

Note the phrases "This model provides strictly an energy price" and "AURORA energy price," indicating the model does not include the avoided capital costs. This conclusion is further buttressed by Staff's Comments in the Rockland Wind project case, wherein Staff stated, "Idaho Power believes, and Staff agrees, that the AURORA-generated avoided cost rate simply represents a market price alternative that primarily reflects the value of energy and does not fully reflect capacity value."[8]

Due to the exclusion of capital costs, it is not surprising that the levelized price of $56.21/MWh is 26% lower than the published PURPA price of $75.88, found by using the Proxy Method to determine the avoided cost. The use of a power supply model, that estimates just the energy costs, as a bench mark for a utility's *full* avoided costs is not equivalent to an "IRP Methodology," which should take into account all relevant costs, including energy and capital related costs.

The actual method used by the utilities to evaluate the cost of new resources in the IRP process includes the use of a power supply model to find the variable cost of the proposed generating units, and then adds to that variable cost all other expected cost items, such as capital and transmission. The table below was included in a handout at Idaho Power's January 20, 2011 Integrated Resource Plan Advisory Council meeting.[9] The four columns and total indicate the net present value of the nine resource portfolios Idaho Power is currently considering for their 2011 IRP. The RECs column is negative based on the assumption that all future resources will be self built projects, and thus the Company could derive revenue from selling the RECs.

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7 IPUC Order No. 32125, Rockland Wind Project, pp. 3-4.

8 Comments of Commission Staff, IPC-E-10-24, p. 3. It appears from the documents in Case No. IPC-E-95-9, wherein the Commission approved the IRP Methodology for large projects, that Commission Staff may have intended the IRP Methodology to mimic the Differential Revenue Requirement Method described above. However, that would require a financial model that would include all capital related costs, not the power supply models currently being used by the utilities.

9 IRPAC meeting handout, p. 9 (Jan. 20, 2011).

Base Case Portfolio Costs (2011-2020)					
	NPV Portfolio Costs 2011$s - 000's)				
Base Case	Variable (Aurora)	Capital	Trans	RECs	Total
1-1 Sun & Steam	$3,042,492	$804,575	$17,925	($24,396)	$3,840,596
1-2 Solar	$2,924,458	$683,497	$20,865	($32,033)	$3,596,787
1-3 B2H	$3,088,318	$0	$98,929	($9,940)	$3,177,307
1-4 SCCT	$3,099,863	$108,835	$22,748	($9,940)	$3,221,506
1-5 SCCT	$3,116,409	$188,415	$19,546	($9,940)	$3,314,430
1-6 CHP	$3,163,107	$398,453	$15,798	($9,940)	$3,567,418
1-7 Balanced	$3,086,075	$441,042	$16,349	($15,384)	$3,528,082
1-8 Pumped Storage	$3,093,402	$416,887	$23,099	($15,206)	$3,518,182
1-9 Distributed Generation	$3,099,631	$114,153	$22,748	($9,940)	$3,226,592

As is clearly demonstrated in this table produced by Idaho Power in its IRP process, the utility's actual "IRP Methodology" includes more than just the power supply model's estimates of variable costs in determining full costs of future resources. It also includes capital costs and transmission. The full costs of these future resources, including both variable and fixed costs, are the utility's actual full avoided costs.

In NIPPC's Production Request No. 67, NIPPC asked Idaho Power to provide the IRP Methodology Model runs that led it to state at oral argument on January 27, 2011, that it could accurately calculate avoided cost rates for projects down to 100 kw in size with the IRP Methodology. In response to No. 67(b), Idaho Power provided a table with its IRP Methodology runs, and stated the table "shows only the avoided cost of energy modeled by AURORA, and does not contain the avoided cost of capacity component, which is added to the value of the energy in determining the total avoided cost rate.[10] In (h) of that same Response the Company added,

> A capacity (fixed) cost credit using a combined cycle combustion turbine as a surrogate resource is then added and any applicable deductions are subtracted to calculate an adjusted avoided cost for each year of the contract.[11]

But the Company did not provide calculations or work papers for this capacity credit, and it has provided no evidence that it has ever provided a QF requesting IRP Methodology rates with such a capacity credit using a surrogate combined cycle combustion turbine (or any other type of surrogate). As discussed above, the filings in the Rockland Wind Project case lacked any

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10 Idaho Power Response to NIPPC Production Request No. 67(b).

11 Ibid.

discussion of such a capacity credit being calculated or added to the IRP Methodology rate for that project.

It should also be noted the Company's discussion of including capital costs within the "IRP Methodology" focuses on "A capacity (fixed) cost credit" and does not include the implications for the present value of the revenue requirement with and without the project being modeled as proscribed by the Commission's as approved method in Case IPC-E-95-9. The methodology by which the Company now asserts it will include a capacity cost is therefore not a commonly recognized methodology for calculating avoided cost rates, and is not in line with differential revenue requirement methodology approved in Case No. IPC-E-95-9.

Conclusion

The "IRP Methodology" currently being utilized to generate PURPA avoided cost rates for projects over 10 aMW and proposed for use in all projects over 100 kilowatts will not be equal to a utility's full avoided costs unless the present value of the revenue requirement is compared with and without the project being modeled. The public record indicates the current implementation of the "IRP Methodology" does not fit within any of the three standard types of methodologies used by other states to calculate avoided costs. Only when capital costs are added and the present value of the revenue requirement calculated can the "IRP Methodology" be considered an estimate of a utility's full avoided cost under the method approved by the Commission.

	Don C. Reading
Present position	Vice President and Consulting Economist
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Honors and awards	Omicron Delta Epsilon, NSF Fellowship
Professional and business history	Ben Johnson Associates, Inc.: 1989 ---- Vice President 1986 ---- Consulting Economist Idaho Public Utilities Commission: 1981-86 Economist/Director of Policy and Administration Teaching: 1980-81 Associate Professor, University of Hawaii-Hilo 1970-80 Associate and Assistant Professor, Idaho State University 1968-70 Assistant Professor, Middle Tennessee State University
Firm experience	Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, Texas, Utah, Wyoming, and Washington. Dr. Reading has more than 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates. In the field of telecommunications, Dr. Reading has provided expert testimony on

	the issues of marginal cost, price elasticity, and measured service. Dr. Reading prepared a state-specific study of the price elasticity of demand for local telephone service in Idaho and recently conducted research for, and directed the preparation of, a report to the Idaho legislature regarding the status of telecommunications competition in that state.
	Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Dr. Reading is currently a consultant to the Idaho Legislature=s Committee on Electric Restructuring. Since 1999 Dr. Reading has been affiliated with the Climate Impact Group (CIG) at the University of Washington. His work with the CIG has involved an analysis of the impact of Global Warming on the hydo facilities on the Snake River. It also includes an investigation into water markets in the Northwest and Florida. In addition he has analyzed the economics of snowmaking for ski area's impacted by Global Warming. Among Dr. Reading's recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also performed analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin. Dr. Reading has prepared econometric forecasts for the Southeast Idaho Council of Governments and the Revenue Projection Committee of the Idaho State Legislature. He has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination. He is currently a adjunct professor of economics at Boise State University (Idaho economic history, urban/regional economics and labor economic.) Dr. Reading has recently completed a public interest water rights transfer case. He

	has also just completed an economic impact analysis of the 2001 salmon season in Idaho.

Publications	"Energizing Idaho", Idaho Issues Online, Boise State University, Fall 2006. www.boisestate.edu/history/issuesonline/fall2006_issues/index.html The Economic Impact of the 2001 Salmon Season In Idaho, Idaho Fish and Wildlife Foundation, April 2003. The Economic Impact of a Restored Salmon Fishery in Idaho, Idaho Fish and Wildlife Foundation, April, 1999. The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997. ACost Savings from Nuclear Resources Reform: An Econometric Model@ (with E. Ray Canterbery and Ben Johnson) *Southern Economic Journal*, Spring 1996. A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988. Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988. "Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983. An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980. *Phosphate and Southeast: A Socio Economic Analysis* (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975.

		Estimating General Fund Revenues of the State of Idaho (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975. "A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In *The American Economist*, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128. "New Deal Activity and the States, 1933-1939." In *Journal of Economic History*, Vol. XXXIII, December 1973, pp. 792-810.