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July 20, 2012

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. GNR-E-11-03
PURPA SAR and IRP Methodologies – Legal Brief of Idaho Power Company

Dear Ms. Jewell:

Enclosed for filing in the above matter are an original and seven (7) copies of the Legal Brief of Idaho Power Company.

Very truly yours,

Donovan E. Walker

DEW:csb
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.	)	CASE NO. GNR-E-11-03 LEGAL BRIEF OF IDAHO POWER COMPANY

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Pursuant to the schedule set forth in Idaho Public Utilities Commission ("Commission") Order No. 32388, Idaho Power Company ("Idaho Power") hereby respectfully submits this legal brief in support of Idaho Power's recommendations to the Commission in the above-captioned matter.

I. INTRODUCTION

A. PROCEDURAL HISTORY

On November 5, 2010, Idaho Power, Avista, and Rocky Mountain Power filed a joint petition in Case No. GNR-E-10-04 requesting that the Commission investigate issues related to avoided cost rates and the State of Idaho's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). In the joint petition, the utilities expressed concern with the volume of intermittent qualifying facility ("QF") generation under PURPA contract or seeking PURPA contracts. Joint Petition at 3-4. Idaho Power noted that at the present rate of growth the volume of QF generation forced on Idaho Power through PURPA contracts could exceed Idaho Power's minimum load in the near term. *Id.* at 4. The utilities noted that large QF projects are disaggregating to inappropriately take advantage of more favorable published avoided cost rates intended for small projects. *Id.* at 5-6. The utilities also noted that the rapid expansion of intermittent QF generation is creating significant system reliability, integration, and operational impacts that are inadequately addressed under Idaho's current implementation of PURPA and result in direct and substantial harm to customers. *Id.* at 4-5.

In comments filed on December 22, 2010, in Case No. GNR-E-10-04, Idaho Power provided additional discussion regarding its concerns with the current avoided cost methodologies and related PURPA implementation issues. Idaho Power noted that the current method of calculating avoided cost rates in Idaho is leading to results that are inaccurate and inflated. Comments of Idaho Power at 17-19, Case No. GNR-E-10-04 (Dec. 22, 2010). Idaho Power noted that power purchased under such contracts is purchased at rates significantly exceeding those required by PURPA to the substantial harm of utility ratepayers and the public interest. *Id.* at 19 ("It is difficult to see how the customers are held neutral, or indifferent, with a requirement to enter into FESAs, at above-market prices, for power that is not needed on the system and also withholds the value that could be derived from the RECs."). In sum, the utilities urged the Commission to investigate its avoided cost rates and related PURPA implementation issues and to make changes as necessary to remedy the situation and to protect the public interest. Joint Petition at 1, 8. By way of interim relief to reduce the impact of these problems, the utilities asked the Commission to immediately reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW. *Id* at 2, 8.

On December 3, 2010, the Commission declined to immediately lower the eligibility cap; instead the Commission issued notice of a modified procedure to serve as Phase I of the Commission's investigation. Order No. 32131. The modified procedure involved written comment and oral argument on the question of whether to lower the eligibility cap as an interim protective measure. The Commission indicated that any decision to lower the eligibility cap would become effective December 14, 2010. *Id.* at 9. On February 7, 2001, the Commission issued Order No. 32176 in which it determined to temporarily lower the eligibility criteria from 10 aMW to 100 kW for all wind and solar QFs effective December 14, 2010. The order also directed the parties to meet to establish a proposed schedule for Phase II of the investigation.

On February 25, 2011, the Commission issued Order No. 32195 in which it established a schedule for Phase II of its investigation, designated as Case No. GNR-E-11-01. The purpose of Phase II was to determine a long-term solution to the problem of large projects that disaggregate into small projects and take inappropriate advantage of published avoided cost rates. After a technical hearing and other modified procedure, the Commission issued Order No. 32262 on June 8, 2011, in which it decided to address disaggregation by making permanent the 100 kW cap on eligibility to published avoided cost rates for wind and solar QFs.

Order No. 32262 also directed the parties to meet to establish an issue list and a schedule for Phase III of the Commission's investigation into avoided cost rates and related PURPA issues. The Commission stated that it was initiating "additional proceedings to allow the parties to investigate and analyze both the SAR Methodology and the IRP Methodology" and that the Commission encouraged "a full examination of the application of the IRP Methodology and [is] open to considering alternatives to the current methodologies." Order No. 32262 at 8-9. In its Notice of Review for Phase III—designated Case No. GNR-E-11-03—the Commission further described the scope of the instant case:

> [T]he Commission seeks information regarding the appropriateness of both the SAR and the IRP-based avoided cost methodologies. Specifically, the calculation of avoided cost rates for both published and negotiated contracts, is being re-examined. . . . [T]he Commission anticipates that the scope of this inquiry will also include (but is not limited to) considerations regarding the dispatchability of varying resources, curtailment options, integration costs, renewable energy credits, delay security and liquidated damages, timing and schedule of negotiations, and contract milestones.

Order No. 32352 at 4.

In Order No. 32288 dated November 2, 2011, the Commission established a Phase III schedule including the filing of direct and rebuttal testimony in January, May and June of 2012, the filing of all legal briefs by July 20, 2012, and a technical hearing to occur August 7 to August 9, 2012.

On March 12, 2012, Idaho Power filed a Motion for a Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities during the pendency of this proceeding. The Commission, in denying Idaho Power's request for a stay, entered findings, "that the methodologies previously approved by this Commission, as utilized and applied by Idaho Power, do not currently produce rates that reflect Idaho Power's avoided costs and are not just and reasonable, nor in the public interest." Order No. 32498, p. 2. The Commission ordered that all QF contracts with Idaho Power for projects over 100 kW be presented to the Commission for individual evaluation with regard to all terms contained therein. *Id.*

Parties in this docket have previously filed direct and rebuttal testimony. Idaho Power now respectfully submits this legal brief in compliance with the Commission's scheduling order.

B. ***PURPA REQUIRES CUSTOMER INDIFFERENCE***

Congress passed PURPA to encourage the development of renewable energy technology as an alternative to fossil fuel technology and as an alternative to utility owned generation. Under Section 210 of PURPA, a public utility must generally purchase all output from a QF at the utilities "avoided cost" rate. "Avoided cost" is the cost that the utility would have paid for the capacity and energy obtained from the QF if the utility had purchased the capacity and energy from another source or generated the power itself. 18 C.F.R. § 292.101(b)(6); *see also* Order No. 32176 at 1.

The avoided cost rate paid by a utility for QF output must be just and reasonable to the ratepayers of the utility, in the public interest, and must not discriminate against QFs. 16 U.S.C. § 824a-3(b). In determining the avoided cost rate, "the utility must take into account all alternative sources including third-party suppliers and does not have to buy power it does not need." *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration* Facilities, 114 FERC ¶ 61,043 at P9 (2006) (citing *Southern California Edison Company and San Diego Gas & Electric Company*, 70 FERC 61,215 at 61,677-78, *reconsideration denied*, 71 FERC ¶ 61,269 at 62,078 (1995)).

Congress directed the Federal Energy Regulatory Commission ("FERC") to promulgate regulations to implement PURPA. 16 U.S.C. § 824a-3(a)-(b); *Connecticut Light and Power Co.*, 70 FERC ¶ 61,012, 61,023 (1995). FERC's regulations delegate to the States the responsibility to establish avoided cost rates. *Connecticut Light and Power Co., 70 FERC ¶ 61,012,* 61,024. In setting PURPA avoided cost rates, States may not require utilities to pay more than their avoided cost. *Id.* at 61,029-030; *So. Cal. Edison v. Pub. Util. Comm.*, 101 Cal. App. 4th 384, 398-99, 124 Cal. Rptr. 2d 281 (2002). In general, the avoided cost rates paid for QF output are fully recoverable from a utility's ratepayers. It is a fundamental premise of PURPA implementation that ratepayers should remain indifferent to, and unharmed by, avoided cost rates. 16 U.S.C. § 824a-3(b); 18 CFR § 292.304(a)(2); *Indep. Energy Producers Ass'n v. Val.Pub.Utils. Comm'n,* 36 F.3d 848, 858 (9th Cir. 1994). The Commission has recognized the need for this important principle in its implementation of PURPA in the state of Idaho. *See e.g.,* Order No. 32262 at 8 ("PURPA entitles QFs to a rate equivalent to the utility's avoided cost, a rate that holds utility customers harmless—not a rate at which a project may be viable.").

C. CURRENT IDAHO IMPLEMENTATION OF PURPA HARMS CUSTOMERS

Idaho Power has identified several problems with the current implementation of PURPA that result in unnecessarily inflated avoided cost rates that exceed the requirements of PURPA and that have lead to a flood of over-priced PURPA contracts.

Idaho Power's direct testimony in this matter establishes that, as of the time of filing direct testimony in this matter, it currently had 119 Commission-approved QF power purchase agreements that represent a nameplate capacity of 989 MW and a contractual obligation of more than $3.6 billion. Idaho Power Direct Test. M. Stokes at Ex. Nos. 1, 2 (Jan. 31, 2012). The large increase in QF projects on-line and under contract since 2004 increased the power supply expense passed on to customers through Idaho Power's annual Power Cost Adjustment from approximately $40 million in 2004 to approximately $60 million in 2009, and will increase the annual Power Cost Adjustment to more than $120 million in 2012. Direct Test. Stokes at 9-10. Assuming no new PURPA contracts, Idaho Power's annual PURPA power supply cost is expected to increase to $167 million by 2014 and to $186 million by 2026 as contracted projects come online. *Id.* This represents an approximate 465 percent increase in customer-borne cost from 2004 to 2026. *Id.* This will result in dramatic rate increases for all of Idaho Power's customers. Idaho Power Direct Test. L. Grow at 10-11 (Jan. 31, 2012).

Idaho Power has submitted extensive testimony demonstrating that the present system for implementing PURPA in Idaho is resulting in harm to ratepayers. No party to this proceeding has contradicted or rebutted Idaho Power's assertions of customer harm. The Commission itself has found "that the methodologies previously approved by this Commission, as utilized and applied by Idaho Power, do not currently produce rates that reflect Idaho Power's avoided costs and are not just and reasonable, nor in the public interest." Interlocutory Order No. 32498 at 2. As a result, it is incumbent on the Commission to revise its implementation scheme as necessary to eliminate this customer harm and provide for a system whereby customers are indifferent to PURPA purchases while at the same time faithfully fulfilling the requirements of FERC's PURPA regulations and ensuring that QFs receive the true avoided cost rates to which they are entitled.

D. IDAHO POWER'S RECOMMENDATIONS

Idaho Power has recommended five primaryrevisions[1] for the Commission to make to its PURPA implementation scheme which, if adopted, would faithfully implement FERC's PURPA regulations, would better ensure accurate avoided cost rates, and would better ensure that customers are held harmless. Specifically, Idaho Power recommends the following.

1. Authorize Idaho Power to Use a Revised IRP Avoided Cost Methodology for All QFs

First, Idaho Power has recommended that the Commission approve Idaho Power's Hourly Incremental Costmethodology for establishing avoided cost rates for all QFs. Stokes, Direct, p. 4. The Hourly Incremental Cost methodology is a modivied version of the currently approved Integrated Resource Plan ("IRP") based avoided cost

[1] These five primary revisions do not cover all issues that are before the Commission in this proceeding and that are addressed by Idaho Power in its testimony. To the extent this brief omits any such issues, Idaho Power's position is unchanged from its testimony. Idaho Power does not concede any issue not specifically discussed herein, and specifically reserves the right to raise, contest, agree, or otherwise address all issues before the Commission.

methodology. This modified methodology for calculating avoided cost rates is superior to Idaho Power's previous IRP methodology or SAR methodologies for several reasons. First, it is simple and transparent. This increases the ability of all parties—Idaho Power, QF developers, and Commission staff—to apply the methodology and understand its implications. Idaho Power's proposed modified methodology uses the highest cost displaceable resource (rather than using estimated off-system sales price or a proxy/surrogate resource price) to value QF output during periods of system surplus generation because such an approach better fits FERC's definition of avoided cost. Lastly, the proposed modified methodology assumes more frequent refreshment of model inputs to minimize the lag between when inputs change and when those changes are reflected in calculated avoided costs. These features allow for an approach to avoided cost calculation which is more closely aligned to the requirements of PURPA than is possible using either the SAR methodology or the previously employed IRP methodology.

2. Authorize Idaho Power to Limit the Term of PURPA Contracts to Five Years

Second, Idaho Power has recommended that the Commission authorize the utilities to enter into PURPA contracts with a five-year term rather than a twenty-year term. Stokes, Direct, p. 4. Idaho Power is not aware of any FERC decision declaring that a five-year limit on fixed price contracts is impermissible under PURPA. In fact, this Commission and the Oregon and California commissions have implemented five-year term limits in the past. Further, in the context of evaluating whether a QF has access to long-term markets necessary to grant a waiver of a utility's must-buy obligation under 210(m), FERC has determined that contracts of one year or more are "sufficiently long-term to meet the statutory requirement that there be 'wholesale markets for long-term sales of capacity and energy' within the meaning of section 210(m)(1)(A)(ii)." *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities,* Order No. 688-A, 119 FERC ¶ 61,305, P 27 (2007). There does not appear to be any good policy reason to assume that FERC would require utilities with a must-buy obligation to offer multi-year term PPAs when a QF selling at market may not have such an option.

Twenty-year contract terms place a disproportionate amount of rate and cost risk on the utility customer, rather than QFs. Furthermore, reducing the contract length will not fatally inhibit QF financing. Because rates would be revisited at five-year intervals when contracts are renewed, the Commission could better ensure that contract rates reflect actual avoided cost rates. For these reasons, five years is an appropriate contract term for Idaho Power.

3. Authorize Idaho Power to Adopt Its Proposed Schedule 73, Which Establishes an Express Process and Timeline for the Negotiation of PURPA Contracts

Third, Idaho Power has recommended that the Commission authorize Idaho Power to adopt its proposed Schedule 73 establishing an express process and timeline to be followed in the negotiation of PURPA contracts. Stokes, Rebuttal, p. 48. This schedule would provide all parties with greater clarity and may diminish disputes regarding inappropriate delays in the contracting process because the expected timeline for the process would be established by Tariff Schedule. Staff, the three utilities, and all intervenors that have addressed the issue support the establishment of a formalized negotiation process. Schedule 73 is closely modeled on tariffs used for years in

Wyoming, Utah, and Oregon and is approved by the commissions of those states. Specific objections raised by intervenors are not related to the merits of Schedule 73. In sum, Schedule 73 fulfills a present need and is ready for implementation.

4. Authorize Idaho Power to Adopt Its Proposed Schedule 74, Which Establishes a Process for Curtailment of QF Output Consistent with FERC Rule 304(f)

Fourth, Idaho Power has recommended that the Commission authorize Idaho Power to adopt its proposed Schedule 74. Grow, Direct, p. 14. This proposed schedule would establish an express process and right to curtail QF output under circumstances already authorized by FERC in Section 304(f) of the FERC PURPA regulations. Adoption of Schedule 74 would provide Idaho Power with an approved method to implement Section 304(f)'s provisions which relieve a utility from its mandatory purchase obligations under certain light loading operational circumstances. PURPA and FERC's regulations permit such curtailment in order to avoid harmful cost impacts to Idaho Power customers caused when Idaho Power must back down base load resources to accommodate QF output during light load conditions and then suffer an otherwise unnecessary increase in cost when it must use higher cost power sources during the interval required to ramp base load resources back up during higher load conditions.

5. Establish that Utility Purchasers of QF Output Own the RECs Associated with that Output

Fifth, Idaho Power has recommended that the Commission declare that when a utility is compelled to purchase QF output under the PURPA must-buy obligation, the environmental attributes associated with the QF output remain bundled with the QF energy and capacity and the purchasing utility is therefore the owner in the first instance of any RECs that subsequently may be associated with the QF output. This result is permissible under PURPA; indeed, FERC has held that the ownership of RECs is controlled by state law not by PURPA. *American Ref-Fuel Co.*, 105 FERC ¶ 61,004, P 23 (2003), reh'g denied, 107 FERC 61,016 (2004), *appeal dismissed sub nom., Xcel Energy Servs. v. FERC*, 407 F.3d 1242 (D.C. Cir. 2005). This result also prevents QFs from taking advantage of ambiguity or uncertainty under Idaho law to unilaterally lay claim to RECs. This result also recognizes the reality that the utility and its customers are purchasing renewable generation. Finally, this result recognizes that states create RECs and that the value of RECs associated with energy sold under a PURPA contract should appropriately be retained fo rhte benefit of the customers that must purchase that generation—a result that better serves the public interest.

II. ARGUMENT

A. THE COMMISSION SHOULD AUTHORIZE IDAHO POWER TO USE THE HOURLY INCREMENTAL COST METHODOLOGY FOR ALL QFS

In this section, Idaho Power sets forth the applicable legal requirements for administratively determined avoided costs, describes how its proposed avoided cost methodology is consistent with federal regulations, explains why its methodology complies with the legal requirements, and explains why Intervenor's criticisms should be discounted.

1. Statutory and Regulatory Definition of Avoided Cost

The legal requirements governing the price of QF energy and capacity originate in Section 210(b) and 210(d) of PURPA. 16 U.S.C. § 824a-3(b), (d). Section 210(b) prohibits utilities from paying "a rate which exceeds the incremental cost to the electric utility of alternative electric energy." 16 U.S.C. § 824a-3(b). Section 210(d) of PURPA defines "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, but for the purchase from such [QF], such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(d). FERC, in turn, promulgated rules implementing PURPA, including Section 210(b) and 210(d).

a. "Avoided Cost" Defined ("Rule 101(b)(6)").

FERC Rule 101(b)(6) defines "avoided cost" as the incremental cost of energy or capacity, or both, that the utility either (1) did not generate; or (2) did not purchase from another source as a result of the QF purchase:

> *Avoided costs* means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

18 CFR § 292.101(b)(6) (2011).

b. FERC's Four Factors Affecting Avoided Cost ("Rule 304(e)").

FERC Rule 304(e) prescribes four broad factors states are to consider "to the extent practicable" when setting avoided costs. 18 CFR § 292.304(e). The first factor is the system avoided cost data and planning data a utility is required to provide pursuant to 18 CFR § 292.302.[2]

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[2] Rule 302(b) requires each electric utility to publish the following data:

> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>
> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

The second factor is "[t]he availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including":

> (i) The ability of the utility to dispatch the qualifying facility;
>
> (ii) The expected or demonstrated reliability of the qualifying facility;
>
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
>
> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
>
> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
>
> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
>
> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities;

18 CFR § 292.304(e)(2). The third factor is the extent to which the QFs energy and capacity actually allows the utility to avoid capacity additions and fuel expenses.

> The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this

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> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

18 CFR § 292.302(b) (required by 18 CFR § 292.304(e)(1)).

> 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 CFR § 292.304(e)(3). The fourth and final factor is line loss costs and savings.

> 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 CFR § 292.304(e)(4).

FERC recently explained how Rule 304(e) factors into a State's procedures for setting avoided costs:

> [W]e emphasize that the determinations that a state commission makes to implement the rate provisions of section 210 of PURPA are by their nature fact-specific and include considerations of many factors: our [Rule 304(e)] regulations thus provide state commissions with guidelines on factors to be taken into account, "to the extent practicable," in determining a utility's avoided cost of acquiring the next unit of generation.

California PUC, 134 F.E.R.C. ¶ 61,044, P 36 (F.E.R.C. 2011)(footnote omitted). State Commissions have an obligation to provide some analysis of the four factors of Rule 304(e), they need not quantify the effect of each factor on the approved rate. *Ass'n of Bus. Advocating Tariff Equity v. Mich. Pub. Serv. Comm'n*, 216 Mich. App. 8, 29-30 (Mich. Ct. App. 1996)(finding that state commission's incorporation of the utility's analysis of Rule 304(e) factors with statements of its own was legally sufficient).

c. PURPA Does Not Permit Avoided Cost Rates to Subsidize QF Development.

Adhering to the statutory and regulatory definition of avoided cost is not merely a legal formality, but also ensures the policy goal of customer indifference. Straying from the definition makes avoided cost rates more likely to diverge from actual avoided costs. Divergence has repeatedly led to significant overpayment to QFs. Hieronymus,. Direct, p.30-32. The impact on utilities and customers has in some instances been dramatic as excessive avoided cost rates bring a glut of QFs. *Id.* (recounting instances in California and New York of excessive QF rates leading to QF commitments forced on utilities exceeding actual avoided cost by billions of dollars in aggregate). Idaho Power experienced a tidal wave of new QF generation beginning in 2010 when its avoided cost rates substantially exceeded the actual value of QF output to Idaho Power.

An avoided cost rate set higher than the actual cost of a displaced source of power for the utility amounts to a subsidy, and is contrary to PURPA and Idaho law. According to FERC:

> The avoided cost standard dictates that QFs should be paid consistent with, not their social value, but the costs of displaced sources of power to utilities. The criteria for qualification as a QF must carry the burden of assuring that the QF's mode of generation is socially desirable.

Direct Test. Hieronymus at 38 (quoting page 30 of FERC NOPR RM88-6). This Commission has also recognized the foundational PURPA principle of ratepayer indifference:

> Ratepayers should be indifferent to whether a resource serving them was constructed by a utility or an independent developer. The cost and quality of service provided by either should be the same. Ratepayers should not be asked to subsidize the QF industry through the establishment of avoided cost rates that exceed utility costs that would result from an effective least cost planning process.

In the Matter of the Application of the Idaho Power Company for Approval of Prices for the Purchase of Electricity from Cogenerators and Small Power Producers Qualifying Under Section 210 of the Public Utility Regulatory Policies Act of 1978, IPUC Case No. IPC-E-93-28, Order No. 25884 (1995).

In sum, FERC and this Commission have recognized that rates for purchases from QFs satisfy the ratepayer indifference requirement when the incremental cost to the utility of alternative energy is equal to the cost if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity. Any amount in excess of this equation amounts to a subsidy and is unlawful under PURPA.

2. <u>The Hourly Incremental Cost Methodology</u>

In this proceeding Idaho Power has proposed a single methodology for determining avoided cost prices for all QFs of any size. Idaho Power proposes to use the AURORA model to determine the highest displaceable incremental energy cost being incurred during each hour of the QF's proposed contract term. The result is a time series of displaceable incremental or avoided costs-one for each hour of the proposed contract term. This time series of hourly avoided costs is then multiplied by the QF's supplied hourly generation profile. These products are then summed over heavy load and light load hours for each month to arrive at heavy load and light load pricing for each month of the contract term. The details of the methodology are described in pages 10-33 of the Direct Testimony of Karl Bokenkamp.

Idaho Power's proposed modified methodology, or Hourly Incremental Cost methodology[3] differs from Idaho Power's previous IRP model in two important respects: First, whereas the previous IRP methodology required two AURORA simulations to calculate avoided energy costs—one with the proposed QF resource and one without—the proposed modified methodology multiplies hourly system incremental costs from a single simulation by an hourly QF generation forecast to calculate avoided energy cost. And, second, whereas the previous IRP methodology valued surplus QF generation at the modeled market price, the modified methodology values such generation at the marginal cost of its most expensive displaceable generator or power purchase contract. Idaho Power also is proposing to change the type of proxy unit used to determine the avoided cost of capacity and other input assumptions used in the previous methodology, and to increase the frequency with which such inputs are refreshed.

The modified methodology does an excellent job of calculating avoided costs that are both current and representative of the QF's actual value to the utility without unnecessary complexity. For this reason, Idaho Power is recommending that its modified methodology be used to calculate avoided costs for all QFs seeking to sell to Idaho Power, including QFs under 100kW seeking standard rate PPAs.

3. ***The Hourly Incremental Cost Methodology Closely Adheres to the Definition of Avoided Cost Established by FERC and PURPA.***

Under Idaho Power's previous IRP methodology, it was assumed that QF generation that was excess to Idaho Power's system load was used to make market sales. Such sales were valued at the AURORA-generated market clearing price.

[3] Idaho Power refers to its proposed revisions as its "proposed modified methodology." Some of Idaho Power's witnesses also have referred to it as the Hourly Incremental Cost methodology. The two terms are used synonymously by Idaho Power.

Bokenkamp, Direct, p. 21. Under the proposed modified methodology, QF energy during periods of system surplus will instead be valued at the highest displaceable incremental cost Idaho Power is incurring during the hour (typically a Company owned thermal plant or a long-term purchase contract). *Id.* Idaho Power's comparison between the previous IRP methodology and the proposed modified methodology is shown in Exhibit 8 to the Direct Testimony of Karl Bokenkamp (as updated by Exhibit 9 to the Rebuttal Testimony of Mark Stokes).

Idaho Power's modified methodology for valuing QF energy better embodies FERC's definition of "Avoided Cost" than does the previous methodology. "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase of the qualifying facility or qualifying facilities, such utility would *generate itself or purchase from another source*." 18 C.F.R. § 292.101(b)(6) (emphasis added). Whereas the previous method based avoided cost on off-system sales—a factor *not* allowed under FERC's definition—the proposed modified method faithfully implements FERC's rule by basing avoided cost on the cost to generate the energy itself or purchase it from another source. *See Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978,* Order No. 69, 45 Fed.Reg. 12,214, FERC Stats & Regs., Regs. Preambles 1977-1981 ¶ 30,128 at 30,870 (Feb. 19, 1980)("A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load.").

4. Proposed Changes to the Avoided Cost Model Inputs

a. Change Proxy Resource from a CCCT to a SCCT for the avoided Cost of Capacity

Idaho Power proposes to use the same method for calculating the avoided cost of capacity used in the previous IRP methodology, but to change the proxy resource type from a combined cycle combustion turbine ("CCCT") to a simple cycle combustion turbine ("SCCT"). Bokenkamp, Direct, p. 22. The purpose of the proxy resource is to represent as accurately as possible the construction costs associated with the type of resource the QF enables the utility to avoid. Because Idaho Power's capacity needs are driven by a few summer peak periods that can be met most economically by constructing a new SCCT, the SCCT is a more appropriate choice for a proxy resource. Bokenkamp, Direct, p. 32-33.

b. Source of Natural Gas Price Forecast for AURORA Simulations

Idaho Power recognizes that stale gas price forecasts have resulted in inappropriate published avoided cost rates in the past and therefore supports efforts to increase the frequency with which gas price forecasts are updated in its AURORA model. An approach Idaho Power supports is to use the appropriate annual natural gas price forecast published by the Energy Information Administration ("EIA") in combination *with* the most-current EIA published short-term forecast available. Stokes, Rebuttal, p. 3-4. Idaho Power noted that the EIA's gas forecast released in January 2012 is already more than 50 percent too high compared to the May 2012 update. Stokes, Rebuttal, p.

4-5. Using the short-term updates will avoid a situation where the utility must offer a PPA with prices it knows are not accurate.

c. Frequency of Refreshing Inputs to the Model

Idaho Power proposes as part of its modified methodology that the company's resource portfolio used to model future avoided cost rates be updated each time Idaho Power receives a new PPA request from a QF (or a request from a QF is withdrawn). Bokenkamp, Direct, p. 29. Such a process will ensure that Idaho Power's avoided cost simulations remain accurate as new resources are added (or subtracted) from the its portfolio. In the past, such frequent updates would have been prohibitively labor intensive. However Idaho Power's modified methodology is capable of frequent updates. Because such updates are feasible, it makes sense that Idaho Power should update its portfolio as often as needed to ensure that it is evaluating current (not past) system conditions.

5. Use of the SAR Methodology Should be Eliminated for Idaho Power

Idaho Power has significant concerns about the continued use of the SAR methodology for any size QF selling to Idaho Power. On March 22, 2012 in this proceeding, the Commission found that "the methodologies previously approved by this Commission, as utilized and applied by Idaho Power, do not currently produce rates that reflect Idaho Power's avoided costs and are not just and reasonable, nor in the public interest." Order No. 32948, p. 2. Almost all of Idaho Power's 119 approved PURPA purchase contracts contain rates derived with the SAR methodology for published, or standard, avoided cost rates (the 80 MW Rockland Wind contract being the only approved contract containing IRP based rates). Idaho Power believes that the prices generated using the SAR model in the past have been biased upward in excess of the company's actual avoided costs. Idaho Power is confident that its proposed modified methodology does not contain such an upward bias. Furthermore, running both the SAR model and the Hourly Incremental Cost model would result in unnecessary administrative burden compared to running only the IRP model.

6. ***The Hourly Incremental Cost Methodology can Accomodate the Four FERC Factors in Rule 304(e)***

FERC Rule 304(e) enumerates four factors to be considered when calculating avoided cost rates for a particular project. The Commission and the Idaho Supreme Court have recognized that these factors can be of particular importance when negotiating PURPA contracts with QFs larger than 10 MW. Rosebud Enterprises, Inc. v. Idaho Public Util. Comm'n, 128 Idaho 609, 620 (1996) ("Rosebud"). Once a QF has provided information about its proposed project and Idaho Power has made an initial determination of avoided costs using its AURORA model, the parties can negotiate any adjustments necessary to address the factors enumerated in FERC Rule 304(e). Idaho Power's proposed Schedule 73 notes this possibility, on Sheet No. 73-2, paragraph 3:

> Within 30 calendar days following receipt of all information required in Paragraph 2, the Company shall provide the owner with an indicative pricing proposal, which may include other indicative terms and conditions, tailored to the individual characteristics of the proposed project.

Stokes, Rebuttal, Exhibit No. 10, p. 2 (emphasis added). Such a process is consistent with the Commission's instruction on how to generate individualized QF rates summarized in Rosebud:

> The IPUC requires that rates and contracts for [facilities that are not eligible for standard rates] be individually negotiated, with a utility's published or filed avoided cost rates used as a

> starting point for negotiations. Individualized consideration is to be given to such issues as line losses, reliability, and the purchasing utility's scheduling ability, and to a project's effect on a utility's load resource balance.

128 Idaho 609, 614-15.

In many cases, the parties may agree that no adjustment to the avoided cost generated by AURORA are necessary either because none of the Rule 304(e) factors apply or because the cost of negotiating a Rule 304(e) adjustment would be larger than the amount of money at stake through an adjustment. But in other cases, particularly with large QFs, the AURORA-generated numbers may substantially misrepresent actual avoided cost unless they are adjusted for the factors contemplated by FERC Rule 304(e). In such cases the parties will need to negotiate an appropriate adjustment to the AURORA results. If the parties cannot reach agreement on the need for an adjustment or its appropriate value, either party can file a complaint asking the Commission to rule on the appropriate adjustment amount. Each decision by the Commission will, in turn, help guide Idaho Power and QFs in future negotiations. In sum, Idaho Power's proposed methodology can accommodate adjustments to address Rule 304(e) and thereby protect ratepayers from paying too much for QF output.

7. ***The Intervenors' Objections to Idaho Power's Proposed Methodology Are Unpersuasive***

Intervenors have raised several objections to Idaho Power's proposed avoided cost rate methodology. However, for the reasons discussed below, intervenors' objections are unpersuasive.

Use of a Single Heat Rate for AURORA Simulations - Intervenors argue that Idaho Power's proposal to assume (in its AURORA model simulations) that each of

Idaho Power's generating units operates at its the most efficient heat rate regardless of its load for the units, results in undervaluation of QF energy. Reading, Direct, p. 28-29. This does not take into account the entire operation of the methodology. While it is true that Idaho Power's modified methodology assumes a single heat rate for each thermal resource regardless of load level, and that such an assumption reduces calculated avoided costs, the methodology mades another simplifying assumption that increases calculated avoided costs and counters this effect, Idaho Power values all QF output for any hour at the incremental cost of its most expensive displaceable resource during such hour, regardless whether that displaceable resource can be backed down to make room for any or all of the QF generation. Bokenkamp, Direct, p. 25.-26. This assumption means that the QF output will be valued equal to or higher than Idaho Power's avoided cost determined without this simplifying assumption. However, this upward bias, and the downward bias associated with modeling a single heat rate for each thermal unit, tend to cancel each other out. Mr. Reading's assertion that QF energy is undervalued under the modified methodology is unsupported by the evidence.

Comparability between pricing of Idaho Power-owned Resources and QFs - Intervenors contend that Idaho Power's proposed methodology leads to avoided cost rates that are lower than the utility's own cost to build new capacity. Reading, Direct, p. 32. However, Idaho Power has explained that its proposed methodology takes into account certain physical differences between how utility generators and QFs are operated which explain the difference between the IRP resource costs and resource costs under Idaho Power's modified methodology. Stokes, Rebuttal, p. 15-18. These differences include a 65% annual capacity factor for the CCCT IRP resource and a 92%

capacity factor for the Hourly Incremental Cost resources. Id. at 15. With a higher capacity factor, the QF delivers energy during a considerable number of hours during which the Company's cost to operate its existing resources are relatively low. Consequently, the costs the QF allows the utility to avoid during these hours are relatively low. If the QF operated in the same manner as the IRP resource, the rate under the methodology would increase substantially. Id. Furthermore, the period over which the 2011 IRP cost is levelized is 30 years and, the Hourly Incremental Cost QF is levelized over a 20-year period. Id. Lastly, Idaho Power explains that the natural gas prices used to calculate the 2011 IRP price and its proposed methodology have changed, again explaining the difference in resulting avoided costs. Id. at 18. Simply put, Idaho Power has explained that its proposed methodology accounts for the physical and operating differences between a QF and a utility owned generator, explaining why the two are treated differently in incremental cost calculations.

Treatment of Surplus QF Generation - Intervenors argue that the PURPA must-take obligation is incompatible with Idaho Power's proposal to disregard potential opportunity sales of QF power. Schoenbeck, Direct, p. 21. In practice, direct sales are virtually impossible for power from intermittent QFs because the amount of energy to be delivered is uncertain and subject to curtailment by the QF without penalty. Park, Direct, p. 9. In addition, FERC's unbundling of the bulk transmission system complicates the task of selling energy since the utility must undesignate the QF as a network resource before making a opportunity sale of the QF output. Park, Direct, p. 10. Most importantly, FERC's rules implementing PURPA do not require utilities to include off-system sales when determining their Avoided Cost. FERC has stated that when PURPA requires the utility to take QF output in excess of utility load, "the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load." City of Ketchikan, 94 FERC ¶ 61,293, 62,062 (2001). FERC has also noted that a utility "does not have to buy power it does not need." New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, 114 FERC ¶ 61,043, P 9 (2006) (citing S. Cal. Edison Co., 70 FERC ¶ 61,215, 61,677-78, reh'g denied, 71 FERC ¶ 61,269, 62,078 (1995)).

Transparency and Practicality of Idaho Power's Proposed Methodology - Intervenors argue that Idaho Power's proposed methodology is too complex because it involves a large number of inputs and the need for continuous updating. Intervenors complain that this complexity makes it difficult for them to evaluate the reasonableness of the avoided cost rates generated by the Idaho Power methodology and that the complexity gives the utility too great and opportunity to game the outcome. Reading, Direct, p. 31-32; Shoenbeck, Direct, p. 21. Idaho Power disagrees with the contention that its proposed methodology is overly complex. As discussed in Idaho Power testimony, the proposed methodology is simple and transparent. Stokes, Rebuttal, p. 19. The AURORA model is used to determine the dispatch of utility owned resources; beyond that all other information and calculations are done in an Excel spreadsheet. It becomes simple to understand once people are given the opportunity to work with it. Id. Because all the information used is available to all the parties, gaming should not occur.

Carbon Adder - Intervenors argue that Idaho Power wrongly excludes carbon costs, which are included in Idaho Power's IRP. Schoenbeck, Direct, p. 24-25. However, it is proper to exclude carbon costs from the IRP because carbon costs are not at this point real, nor are they included in customer rates. Stokes, Rebuttal, p. 38. Until these carbon costs are real and a utility may avoid incurring them by purchasing from a QF, it is improper to include them in any avoided cost calculation.

In conclusion, Idaho Power has effectively demonstrated that none of the objections raised by intervenors represents a fatal flaw in Idaho Power's proposed methodology.

8. The Commission Should Maintain its Presently Required Delay Damages and Delay Damage Security in QF Contracts

The provisions regarding Delay Damages and Delay Damage Security contained in the Commission-approved PURPA Firm Energy Sales Agreements ("FESA") are necessary, reasonable, non-punitive, and in the public interest. Moreover, each party that entered into a FESA is precluded from challenging such provisions under the well-established doctrines of res judicata and collateral estoppel.

Delay liquidated damages provisions have been included in PURPA FESA contracts approved by the Commission since at least 2007. See, Case No. IPC-E-06-36. In addition, one of the first Commission approved FESAs to contain terms requiring the project to post liquid security was the FESA for Cassia Gulch Wind Park and Tuana Springs Energy, Case No. IPC-E-09-24. In that case the Commission approved provisions requiring the posting of liquid security in the amount of $20 per kW of project capacity.

The Commission considered and approved provisions providing for the posting of liquid security in the amount of $20 per kW of project capacity in at least four other PURPA FESAs. See, Case No. IPC-E-09-18, IPC-E-09-19, IPC-E-09-20, IPC-E-09-25. The Commission has since analyzed and approved provisions requiring the posting of liquid security in the amount of $45 per kW of nameplate capacity in at least twenty-seven different PURPA FESAs. See, Case No. IPC-E-10-02, IPC-E-10-05, IPC-E-10-15, IPC-E-10-16, IPC-E-10-17, IPC-E-10-18, IPC-E-10-19, IPC-E-10-22, IPC-E-10-26, IPC-E-10-37, IPC-E-10-38, IPC-E-10-39, IPC-E-10-40, IPC-E-10-41, IPC-E-10-42, IPC-E-10-43, IPC-E-10-44, IPC-E-10-45, IPC-E-10-47, IPC-E-10-48, IPC-E-10-49, IPC-E-10-50, IPC-E-11-09, IPC-E-11-10, IPC-E-11-25, IPC-E-11-26, and IPC-E-11-27. In approving the change in the amount of delay damage security that is acceptable for such contracts from $20 to $45 per kW of nameplate capacity, the Commission specifically found such delay security to be reasonable, necessary, and not to be punitive. Order No. 31034, p. 3-4, Case No. IPC-E-10-02 (2010).

Idaho Power supports and recommends the Commission's continued requirements to provide for delay liquidated damages, and well as delay damage security in its approved PURPA FESAs. As referenced above this requirement has been specifically addressed in several cases, and found by the Commission to be a just, reasonable, and appropriate term for a PURPA QF contract that is in the public interest.

> With regard to the reasonableness of liquidated damages, some witnesses, such as Dr. Reading, focus only upon the comparison to the cost of replacement power should the QF not bring its project on-line when it commits itself to a Scheduled Operation Date that it chooses in the contract. This highlights an important part of Idaho Power's case that it provided much evidence of in its direct testimony, and that is typically the Company can acquire replacement power from other available sources at a cost that is below the contract price in the PURPA contract. This, however, is not the only measure of harm and damages. In addition to the system operation and planning problems that failure to bring generation units on-line in a timely manner and when they are scheduled to come on-line, there is the substantial value that the QF gets by locking in a price, and a pricing stream with its contract. If a QF is allowed to come on-line, or not,

> at its choosing with no consequences and no liability for the value of that option, then customers are left in a financially disadvantaged position and uncompensated for the price lock and option they extended to the QF project. There are financial instruments that can be purchased that would allow a utility to lock in a 20-year, or long-term, stream of prices, and have the option to not execute on that option at a date certain in the future. Such products are very costly, and could be as much as $5 per MWh of power. The $45 per kW of nameplate capacity is very small in comparison, but at least provides an agreed upon valuation of an assessment of risk that the customers are bearing associated with whether a QF generator brings its project on-line when it commits that it will.

Stokes, Rebuttal, p. 46-47.

Idaho Power must routinely buy and sell electricity as much 18 months in advance of the month that is needed (bought) or not needed (sold) as dictated by Idaho Power's Risk Management Policy. The amounts that are bought and sold are based on the overall portfolio position (surplus/deficit) that includes company-owned resources and QF contracts. When a QF resource fails to come on-line by the Scheduled Operation Date, Idaho Power must replace this energy by making a market purchase, assuming transmission capacity is available to get the energy to Idaho Power's system. Because the transaction is done closer to real time, market prices can be higher than they would have been had Idaho Power been able to execute the transaction earlier in time. There is also the possibility that market prices will be lower than the QF contract, which is typically the current situation if Idaho Power is able to buy energy from the Mid-C market. If transmission capacity is not available from the Pacific Northwest, the energy must be bought from the east side of the system where market liquidity is an issue and prices are almost always higher.

Regardless of whether market prices are higher or lower than prices contained in the QF contract, Idaho Power's customers end up assuming the risk associated with the uncertainty, and have no control over whether the QF energy will be there or not. There is value associated with reducing or eliminating risk even if the potential positive and negative outcomes are evenly split. A fixed rate QF contract eliminates this risk for the QF developer and pushes it entirely onto Idaho Power's customers. As stated in Mark Stokes' rebuttal testimony, "There are financial instruments that can be purchased that would allow a utility to lock in a 20-year, or long-term, stream of prices, ***and have the option to not execute on that option at a date certain in the future***. Such products are very costly, and could be as much as $5 per MWh of power. Stokes, Rebuttal, p. 47 (emphasis added). The financial instrument referenced above would be a "put" option. It is important to note the emphasized section of the passage above in that a put option allows a party to not execute on the option if conditions are not favorable for the option holder. It is exactly this option that is available to the QF, and the exercise of which the QF my choose or not choose depending upon the favorableness, or unfavorableness of the prices contained in its FESA in relation to market prices or other factors. In this way, a QF has the ability to eliminate its own downside, to the direct and substantial harm and detriment of Idaho Power's customers, and take advantage of the upside. Consequently while in theory, one may argue that prices may vary either above or below those set in the FESA, it is the QF that has the ability to eliminate the downside, from its perspective, and it is the customers that take all of the risk, and shoulder a disproportionate amount of price deviation from that which is contracted for.

The delay damage and delay damage security provisions that the Commission has evolved, approved, and implemented as part of its federally delegated responsibility to implement PURPA in the state of Idaho, represents a just, reasonable, necessary, and non-punitive provision of a PURPA QF contract with a utility. It is aimed at providing compensation for cost and risk allocations in the relationship between the utility and the QF that are difficult to quantify with precision, but are none-the-less very real to the utility and its customers. Idaho Power asks that the Commission continue to authorize and require the provisions in a PURPA QF contract that provide for delay damages and delay damage security.

Equally important, the doctrines of res judicata and collateral estoppel preclude the parties from challenging the Commission's Final Orders related to the delay damages and delay damage security contained in the relevant FESAs. The United States Supreme Court has clearly held that a litigant's failure to raise justiciable issues in a prior administrative proceeding precludes that litigant from raising them in a later administrative proceeding and in subsequent litigation. *See Astoria Fed. Sav. & Loan Ass'n v. Solimino*, 501 U.S. 104, 107–08 (1991); *see also* Rest. 2d. Judgments § 83, cmt. b (1982) ("Where an administrative forum has the essential procedural characteristics of a court,… its determinations should be accorded the same finality that is accorded the judgment of a court. The importance of bringing a legal controversy to conclusion is generally no less when the tribunal is an administrative tribunal than when it is a court.").

Here, the issues of Delay Damages and Delay Damage Security were raised and addressed in Commission cases mentioned above. After the Commission approved the relevant FESAs and issued Final Orders related to the same, the parties could have sought reconsideration with the Commission or appealed the decision to the Idaho Supreme Court. Put another way, each parties was afforded court-like substantive and procedural due process to challenge the Commission's Final Order. No such challenged occurred. The parties, therefore, are precluded from litigating the reasonableness of the Delay Damages and Delay Damage Security in this proceeding.

B. ***<u>THE COMMISSION SHOULD LIMIT THE TERM OF PURPA QF CONTRACTS TO FIVE YEARS</u>***

Idaho Power requests that all PURPA contracts with forecasted avoided cost rates be limited to a five-year term, as opposed to the current twenty year-term. Setting a length of five years for PURPA contracts is within the Commission's discretion. By limiting the term of all new PURPA contracts to five years, the Commission remains faithful to its charge to implement PURPA and FERC's PURPA regulations while ensuring that cuatomers are protected from the risk associated with the uncertainty of avoided cost rates forecasted over multiple decades—a risk more appropriately borne by QF investors. Further, limiting the term of PURPA contracts to five years will not discourage or hinder QF investment or QF development because QFs will can renew contracts every five years. The main difference between a twenty-year contract term and a series of five-year contracts is that rates set in five-year intervals at each contract renewal will more accurately reflect a utility's actual avoided costs than rates set once at the beginning of the twenty-year period. For the reasons discussed below, Idaho Power urges the Commission to adopt a five-year term for all PURPA contracts.

1. ***<u>The Commission has Authority to Set a Five-Year Term for Fixed Price Contracts</u>***

The Commission implements PURPA pursuant to the rules and regulations promulgated by FERC. *See* 16 U.S.C. § 824a-3(f). However, neither PURPA nor FERC place explicit limits on permissible contract lengths, leaving the states broad discretion to determine what contract length is appropriate. "A state has broad authority to implement PURPA with respect to the approval of purchase contracts between utilities and QFs." *N. Am. Natural Res., Inc. v. Mich. Pub. Serv. Comm'n*, 73 F. Supp. 2d 804, 807 (D. Mich. 1999) (citing *Crossroads Cogeneration Corp. v. Orange & Rockland Utils.*, Inc., 159 F.3d 129, 135 (3d Cir. 1998)); *see also Indep. Energy Producers Ass'n, 36 F.3d at 85.* Without FERC regulations prescribing a PURPA contract length, the Commission must use its own judgment to determine what contract length is appropriate.

Intervenors argue that the Commission is required by PURPA and FERC regulations to set a contract length that guarantees investment in QF development. Clearwater Paper Corp., J.R. Simplot Co., Exergy Development Group of Idaho, LLC, Reading, Direct, p. 46; Northside Canal Co., Twin Falls Canal Co., Renewable Energy Coalition, Schoenbeck, Direct, p. 35. Dr. Reading combines the option available to QFs to have a predetermined rate available over the course of the entire contract and the requirement that States encourage QF development found in PURPA Section 210 to formulate a requirement that States establish contract lengths that will spur investment in QFs. Reading, Direct, p. 46. However, Dr. Reading overstates the impact of FERC's guidance and his reliance on these primciples is misplaced regarding the length of a contract term. PURPA does not require that QFs be able to obtain financing, only that the QF have the option of obtaining certainty with an avoided cost rate fixed over the term of the contract. 18 C.F.R. § 292.304(b)(5); 18 C.F.R. § 292.304(d); Order No. 69, 45 Fed.Reg. at 12,224. The Idaho Commission has previously rejected the suggestion that a PURPA contract should be structured to promote the viability of QF projects. *See* Order No. 32262 at 8 ("PURPA entitles QFs to a rate equivalent to the utility's avoided cost, a rate that holds utility customers harmless—not a rate at which a project may be viable."). A five-year term satisfies the FERC requirement that the term be fixed over the entire term of the contract. There is no conflict with PURPA or FERC on this point.

Idaho Power is not aware of any FERC decision declaring that a five-year fixed price contract is impermissible under PURPA. In fact the Idaho Commission has repeatedly used its discretion to adjust the length of Idaho Power PURPA contracts, reducing PURPA contract term from 35 years to 20 years in 1987, down to five years in 1992, then back to years 20 in 2002. *See* Commission Staff Direct Test. R. Sterling at 25 (May 4, 2012); *In the Matter of the Review of the Idaho Public Utilities Commission's Policies Establishing Avoided Costs under the Public Utility Regulatory Policies Act of 1978*, IPUC Case No. U-1500-170, Order No. 21630 (1987); *In the Matter of the Application of Idaho Power Co. for an Order Approving the Methodology for Avoided Cost Rate Negotiations with Qualifying Facilities Larger than 1 MW*, IPUC Case No. IPC-E-95-9, Order No. 26576 (1996); *In the Matter of the Investigation of the Continued Reasonableness of Current Size Limitations for PURPA QF Published Rate Eligibility and Restrictions on Contract Length*, IPUC Case No. GNR-E-02-01 (2002). Furthermore, in the past the Oregon PUC has used its discretion and authority to also reduce the contract term available to certain QF generators to five years. *See* Oregon PUC Order No. 84-742, at 3 (1984). California has also approved PURPA fixed rate contracts with five-year terms. *See Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-Run and Long-Run Avoided Costs, Including Pricing for Qualifying Facilities*, California PUC Rulemaking 04-04-003, Decision 07-09-040 2007 Cal. PUC LEXIS 443 (2007). Further, in the context of evaluating whether a QF has access to long-term markets necessary to grant a waiver of a utility's must-buy obligation under 210(m), FERC has determined that contracts of one year or more are "sufficiently long-term to meet the statutory requirement that there be 'wholesale markets for long-term sales of capacity and energy' within the meaning of section 210 (m)(1)(A)(ii)." *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688-A, 119 FERC ¶ 61,305, P 27 (2007). There does not appear to be any good policy reason to assume that FERC would require utilities with a must-buy obligation to offer multi-year term (in excess of even one-year) PPAs when a QF selling at market may not have such an option.

2. ***A Shorter Contract Term Protects Customers by Implementing More Accurate Avoided Cost Rates***

PURPA and FERC regulations require that states establish rates for purchase from QFs at the utilities "full avoided cost." *S. Cal. Edison Co. v. FERC*, 443 F.3d at 95; 18 CFR § 292.304(b)(2). FERC also requires that states use procedures to forecast a utilities avoided cost and no more. 18 CFR § 292.304(b)(2); *Conn. Light & Power Co.*, 70 FERC ¶ 61,012, 61,029 n.46. The Idaho Commission has stated that customers should be "indifferent" to rates paid to independent power producers. IPUC Order No. 25884. However, these rules only apply when setting rates; if a rate is set properly, PURPA is not violated if, at the time of delivery of QF output, fixed rates exceed or fall below a utility's actual avoided cost, and FERC will not adjust such rates in a contract. Rebuttal Test. Stokes at 37; 18 C.F.R. § 292.304(b)(5); 18 C.F.R. § 292.304(d); Order No. 69, 45 Fed. Reg. at 12,224. Therefore, states must do their best to forecast rates accurately and hope that, as FERC puts it, over and under estimations of avoided cost "balance out" over time. Order No. 69, 45 Fed. Reg. at 12,224.

However, primarily due to volatile natural gas prices and their role in determining avoided costs, avoided cost rates set in Idaho have not balanced out. Rather, over the past 30 years, QF developers have received a windfall from forecasted avoided costs set too high. Stokes, Rebuttal, p. 7, Chart R1. Long-term contracts in Idaho exacerbate the problem of excessively high-avoided costs. Stokes, Rebuttal, p. 33. Without the ability to retroactively change the rates set in these contracts, utilities and their ratepayers are stuck paying excessive rates for decades in contradiction of PURPA's policy against subsidizing QFs to the detriment of customers. *Id.*; Sterling, Direct, p. 30; Hieronymus, Direct, p. 107; *Independent Energy Producers Ass'n*, 36 F.3d at 858.

The Commission may mitigate the harm caused by over and under estimations of forecasted avoided cost rates by simply shortening the term of PURPA contracts to five years. Direct Test. Sterling at 30-31; Direct Test. Hieronymus at 15; Direct Test. Stokes at 44-45. Once the initial five years of the contract expires and the QF renews, rates for the renewal period will reflect the most recent actual avoided cost data.

QF development will not, as some intervenors claim, be harmed by a shorter contract length because investors will be uninterested in investing in a QF project with a relatively short-term agreement. Direct Test. Reading at 46. In the purely market-based arenas where the must-buy provision of PURPA has been removed under Section

210(m) of PURPA, FERC has found that contract lengths of only one year are sufficient to demonstrate that QFs are able to compete in the energy market. *See* FERC Order No. 688-A, 119 FERC ¶ 61,305, P 27. Also, Intervenors' concerns should be alleviated by the fact that PURPA contracts will be available again at the end of the initial five-year period and a QF need only apply to obtain a new five-year contract with updated rates. Hieronymus, Direct, p. 112; Stokes, Rebuttal, p. 29.

3. ***A Shorter Contract Term Properly Places Investment Risks on the QF and its Investors, and not on Utility Customers***

The current PURPA contract length of 20 years places market risk onto ratepayers that properly belongs on investors and QF developers. Stokes, Direct, p. 45; Hieronymus, Direct, p. 15; IPUC Order No. 25884. Because avoided cost calculations are based upon the natural gas index, they are extremely volatile and have fluctuated dramatically since PURPA was conceived. Stokes, Direct, p. 45. However, in the past QF investors and developers have been insulated from the risk of downward changing rates through long-term contracts at a guaranteed rate. "By locking a single fixed price or a schedule of fixed prices, PURPA projects are hedging the variable market value of the energy for the fixed prices contained in the contract at the expense of [utility customers]." *Id.*; Sterling, Direct, p. 31; Hieronymus, Direct, p. 107. While investors are secure with a long term contract and guaranteed rate, customers, who have no say in whether or not to pay QF prices, are exposed to the possibility that actual market rates will fall and they will be unable to take advantage of lower prices. Rather, the customers must pay QFs at improperly forecasted rates, foregoing the benefits of lower electricity prices. This is exactly what has happened in Idaho. Stokes, Rebuttal, p. 7, Chart R1. Lowering the length of PURPA contract will place the risk of short and long-term price changes away from the ratepayers and back onto investors willing to take that risk. Sterling, Direct, p. 30; Hieronymus, Direct, p. 15. QF developers will receive an initial rate for a five year contract, then accept the risk that prices may change over those five years, and have a new rate adjusted for market conditions when they obtain a renewed contract after the initial five years.

Properly placing market risk on QF investors and developers through shorter contract terms should not greatly impact QF development because QF investors retain the right to continuously renew PURPA contracts every five years which ensures that investors will always recover properly priced avoided cost rates. Hieronymus, Direct, p. 112; Stokes, Rebuttal, p. 29. Also, the risk and benefit with a shorter contract length exists equally for QF investors and ratepayers. It is entirely possible that after an initial term of five years that avoided cost rates for QF projects may go up, allowing QFs renewing after five years to obtain rates they would not otherwise be able to obtain. Sterling, Direct, p. 30; Hieronymus, Direct, p. 111.

The limitation of contract length to five years should apply to all QF project sizes, and not (as Staff recommends) only to projects receiving avoided cost rates calculated using the IRP methodology. Sterling, Direct, p. 31-32. The risks of market price fluctuation exist for projects with SAR modeled rates, just as they do with IRP calculated risks and again those risks are imposed on ratepayers. Stokes, Rebuttal, p. 35. Reducing the contract length of all PURPA contracts available in Idaho is the best means of limiting risk exposure to ratepayers and an exception for QFs qualifying for SAR rates should not be made. In fact, the risk of customer harm because of variance from the prices set at the time of contracting, when those prices are established with the

SAR methodology, is greater than it is with the IRP or Hourly Incremental Cost methodologies.

Finally, reducing the length of PURPA contracts to five years more accurately compares to the rate recovery process utilities use to cover utility generation investments. Intervenors argue that by reducing contract length to five years that QFs are being treated unfairly compared to utility owned resources because utility owned resources are paid throughout the resource's entire life-cycle. Schoenbeck, Direct, p. 9; Clearwater Paper Corp., J.R. Simplot Co., Exergy Development Group of Idaho, LLC, Reading, Rebuttal, p. 48. However, utility recovery of stranded costs is not guaranteed for the entire life cycle of any generation unit. Sterling, Direct, p. 31. Also, utility-owned resources expose customers to less risk than for PURPA resources because utility rates are readjusted. *Id.* Re-adjusting avoided cost rates at the end of an initial five year PURPA contract term would more closely mirror the process of utility rate recovery, providing more accurate rates to customers.

C. <u>THE COMMISSION SHOULD APPROVE IDAHO POWER'S TARIFF SCHEDULE 73—FORMAL CONTRACTING PROCEDURE</u>

Idaho Power respectfully requests in this proceeding "[e]stablishment of a Commission-authorized negotiation process and procedure by which a PURPA QF can obtain a PPA with Idaho Power." Grow, Direct, p. 14. Rocky Mountain Power proposed its own tariff establishing a contract negotiation process closely modeled on tariffs used by Rocky Mountain Power in Wyoming, Utah, and Oregon. *See* Rocky Mountain Power, Clements, Direct, p. 3, Ex. 202("RMP Schedule 38"). Idaho Power followed suit by proposing a contracting process in Tariff Schedule No. 73. Stokes, Rebuttal, Ex. 10 ("Schedule 73"). Schedule 73 is adapted, with minimal change, from RMP Schedule 38.

Changes made by Idaho Power to adapt RMP Schedule 38 are shown as redline markups Idaho Power's rebuttal testimony. Stokes, Rebuttal, Ex. 11.

RMP Schedule 38 "codifies in Idaho the process that Rocky Mountain Power formally uses in Utah and Wyoming and has informally been using in Idaho for several years." Direct Test. Clements at 3. RMP believes it to be "an efficient and productive process for both the Company and potential QFs." Clements, Direct, p. 3. RMP Schedule 38 originated in a Utah work-group in 2002 with participants similar to those in the instant case. *Id.* at 3.

Part I of proposed Schedule 73, is closely modeled on RMP Schedule 38. Schedule 73 would apply to all QFs "who desire to make sales to the Company at avoided cost rates." Schedule 73 details steps a QF can take to obtain a PPA from Idaho Power. Schedule 73 lists information a QF must provide to Idaho Power. In addition, Schedule 73 requires Idaho to respond to a QF by set deadlines. Idaho Power must provide indicative pricing within 30 days of receiving general project information reasonably required for the development of indicative pricing. Idaho Power must provide a draft PPA within 45 days of the QF requesting a draft PPA and providing additional information needed, if any, to prepare a draft PPA. Within 45 days of the parties reaching full agreement on the terms and conditions of a draft PPA, Idaho Power must provide the QF with a final, executable PPA.

Part II of proposed Schedule 73 clarifies for QFs that interconnecting is a separate process set forth in Schedule 72. Part III provides a process for filing complaints regarding specific terms of a PPA wherein a QF must wait 60 days after an impasse with Idaho Power before filing a complaint with the Commission. The waiting period provides time for the parties to resolve a dispute before bringing it to the Commission.

In 2011, the Wyoming Public Service Commission (Wyoming PSC) approved a version of Rocky Mountain Power's Schedule 38. Schedule 73 and RMP Schedule 38 proposed in the instant case are very similar to the Wyoming Schedule 38. In its order approving Schedule 38, the Wyoming PSC highlighted its benefits:

> Importantly, Schedule 38 provides specific terms and conditions, steps and a time frame for RMP and potential QFs to utilize in determining indicative or estimated avoided cost prices for a proposed QF project. The Commission finds the provisions contained in Schedule 38 also provide the flexibility [a QF intervenor] requested by giving the negotiating parties the leeway to agree on specific terms and conditions beyond those described in Schedule 38, and by acknowledging the Commission's continuing authority to review proposed contracts. . . . In addition, Schedule 38 contains a provision, applicable when RMP and the potential QF provider are unable to come to agreement, requiring them to try for 60 days to work out their differences before bringing the issue to the Commission. Finally, a reasonably applied Schedule 38 may assist QFs in obtaining a contract which can be utilized in securing project financing.

In the Matter of the Application of Rocky Mountain Power to Implement a Permanent Avoided Cost Methodology for Customers that do not Qualify for Tariff Schedule 37 - Avoided Cost Purchases from Qualifying Facilities, Wyoming PSC Docket No. 20000-388-EA-11, Record No. 12750, P 58, 2011 Wyo. PUC LEXIS 441 (2011).

1. ***Schedule 73 Will Benefit QFs, Utilities, and the Commission by Lowering Transaction Costs and Reducing Disputes***

By establishing a formal contracting process, Schedule 73 will reduce future disputes regarding grandfathered entitlement to avoided cost rates that have been superseded. Stokes, Direct, p. 44-45. Such disputes often center on when the QF incurred a legally enforceable obligation and whether the parties fulfilled their respective roles in the contracting process. By formalizing the process in a tariff, the Commission would eliminate questions regarding the proper roles of the parties in the negotiation of a QF agreement. QFs would know when they could expect a response from Idaho Power. And, in the face of a rush of QFs seeking to legally enforceable obligations ahead of a rate change, Idaho Power could be assured of a *per se* reasonable window of time within which to conduct its due diligence.

FERC has embraced timelines in implementing PURPA. *See, e.g.,* 18 CFR § 292.207(c)(2) (utility not required to purchase from a QF of 500 kW or more until 90 days after the QF provides notice of its QF status); *see also* 18 CFR § 292.207(b)(3) (90 days for FERC to respond to application for QF certification). Minimum timelines have helped other states to resolve disputes arising from negotiations. *See, e.g.*, *International Paper Co. v. PacifiCorp*, Oregon PUC Docket No. UM 1449, Order No. 09-439, 2009 Ore. PUC LEXIS 374 (2009) (relying on tariff-based negotiating procedure to resolve QF complaint).

Idaho Power's Schedule 73, if approved, could resolve potential disputes regarding contract negotiations before they arise. In short, by establishing de facto reasonable negotiating procedures in tariff, disputes before the Commission could in large part be reduced to a determination of whether each party fulfilled its respective role and met its respective deadlines under the contracting tariff.

2. __Participants Agree That a Commission-Authorized Negotiation Process and Procedure Would be Beneficial__

Formalizing the PPA negotiation process has unified support from IPUC staff, utilities, and QF developers. IPUC Staff believes that a tariff such as RMP Schedule 38 "could be helpful now for both the utilities and project developers" and "would inform both parties of their responsibilities, informational requirements, and timelines." Sterling, Direct, p. 32. IPUC staff added "[i]t could alleviate complaints." *Id.* Rocky Mountain Power and Avista have joined Idaho Power in requesting a formal negotiation process. Clements, Direct, p. 2; Avista, Kalich, Direct, p. 9 ("[A] tariff similar to PacifiCorp's Schedule 38 could be helpful both to the utilities and project developers, and could limit future complaints before the Commission.").

All QF intervenors that have taken a position in testimony also support a formal negotiation process. Twin Falls Canal Co., Northside Canal Co., and Renewable Energy Coalition testified that "[t]ransaction costs can be minimized by having a clear stated time table for the QF contracting process." Schoenbeck, Direct, p. 36. Renewable Energy Coalition, without endorsing specific components, agreed that "elements" of RMP Schedule 38 "would have value for both the utility and the QF" and "would provide transparency, simplicity and certainty to QFs." Renewable Energy Coalition, Sorenson, Direct, p. 4. Clearwater, Simplot, and Exergy, do not endorse the specific tariff schedule proposed by RMP but they agree that *some* type of QF contracting tariff would be useful if designed to prevent a utility from imposing unnecessary delays in negotiations and if it imposes meaningful deadlines on the utility. Reading, Direct, p. 61.

3. No Materially Significant Objections to Schedule 73 Have Been Raised

Some parties, including IPUC staff, have requested that a new proceeding be commenced to establish formal PPA contracting procedures. *See e.g.*, Sterling, Direct, p. 32 (recommending that the Commission direct each of the utilities to prepare a tariff similar to RMP Schedule 38 subject to review and comment in a separate docket). Rocky Mountain Power submitted RMP Schedule 38 for the record in this case on January 31, 2012. Clements, Direct. However, few specific objections to the terms of RMP Schedule 38 — which is nearly identical to Schedule 73 — have been raised, and the objections raised do not appear to merit a separate docket.

Clearwater, Simplot, and Exergy raise the only two specific objections to RMP Schedule 38. First, they contend the tariff "provides no assurance that any particular process will be followed for small QFs seeking published rates and standard contract terms." Reading, Direct, p. 61. Second, they argue that "the deadlines for the utility to respond to QF requests are far longer than deadlines authorized by the other states' tariff from which Mr. Clements supposedly developed the proposed Idaho tariff." *Id*. at 61.

The intervenors' first objection, regarding assurances for QFs seeking published rates, is not really a criticism of RMP Schedule 38 — nor is it a criticism, by association, of Schedule 73. Schedule 73 is intended to apply to all QFs "who desire to make sales to the Company at avoided cost rates." The objection as it relates to "standard contract terms" is misplaced because Idaho does not have standard PPAs for QFs.

The intervenors' second objection—that timelines in RMP Schedule 38 exceed the timelines in other states—neglects that Wyoming Schedule 38 uses an identical timeline. The timelines in RMP Schedule 38 and Schedule 73 are identical to the timelines in Rocky Mountain Power's Schedule 38 approved in 2011 by the Wyoming Public Service Commission ("Wyoming PSC"): 30 days to provide indicative pricing, 45 days to provide a draft agreement, 45 days to provide an executable agreement. RMP

Wyoming Schedule 38 is available at: http://www.rockymountainpower.net/about/rar/wri.html. Rocky Mountain Power's Schedule 38 tariffs for Oregon and Utah do have different timelines than for Wyoming. But RMP Schedule 38 (along with Schedule 73) is not "far longer than deadlines authorized by the other states' tariff from which Mr. Clements supposedly developed the proposed Idaho tariff."

In sum, Clearwater, Simplot, and Exergy agree that some contracting procedure tariff is desirable, and their specific objections are misplaced.

4. Schedule 73 Is Ripe for Commission Approval

For the reasons stated above, Idaho Power agrees with Rocky Mountain Power that the utilities' respective contracting procedure tariffs should be approved without further proceedings. *See* Rocky Mountain Power, Clements, Rebuttal, p. 3. Schedule 73 closely adheres to tariffs that have been approved and used for years in neighboring states. No commenters have raised specific objections that merit additional proceedings. If the Commission decides to order a separate proceeding to consider contracting procedures, Idaho Power respectfully requests that the Commission approve Schedule 73 on an interim basis pending the outcome of that separate proceeding.

D. THE COMMISSION SHOULD APPROVE IDAHO POWER'S TARIFF SCHEDULE 74 - OPERATIONAL DISPATCH

FERC Rule 304(f)(1) excuses a utility from accepting QF output during light load periods if, because of operational circumstances, purchase of QF output will result in costs greater than costs the utility would incur if it did not make the QF purchase and instead generated the energy itself:

> *Periods during which purchases not required.* (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

18 CFR § 292.304(f)(1) (2012). FERC recently acknowledged this exception to the must-buy rule of Section 210 of PURPA. *See Entergy Services, Inc.*, 137 FERC ¶ 61,199, P 54-56 (2011). Idaho Power has proposed Schedule 74 to clarify the process for invoking a Rule 304(f) curtailment. As explained below, Idaho Power's customers increasingly are incurring costs arising from excess QF generation during light load periods; FERC and PURPA intend that those costs not be borne by the utility customer; and thus relieves the utility from its obligation to purchase during these defined periods. Idaho Power's proposed Schedule 74 reasonably implements FERC Rule 304(f) to correct this misallocation of costs.

1. ***<u>FERC Rule 304(f) is a Viable Exception to PURPA's Must-Buy Obligation</u>***

FERC explained, in its order adopting Rule 304(f), that its intent was to make an exception to the must-buy obligation during light load periods when certain system conditions are present:

> The proposed rule provided that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases will result in net increased operating costs to the electric utility. This section was intended to deal with a certain condition that can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system

> demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output.

Order No. 69, 45 Fed. Reg. at 12,227. During certain system conditions when loads are light, accepting QF purchases will force the utility to shut down one or more of its most economical units in order to make room on its system for QF purchases. When system loads go back up (typically the next on-peak period), the utility must rely on its more expensive peaking units until the slower starting, more economical units are available. The result is that the QF purchases have caused the utility to substitute peaking units for base load units—with a resulting higher cost to the utility's customers. This substitution is uneconomical, and can also lead to system emergency if the utility has inadequate peaking units available to meet its next peak.

While PURPA generally does not permit utilities to curtail QFs for "economic" reasons, 304(f) is an explicit exception. PURPA's exception allowing curtailment during light load periods serves several important policy objectives. It reduces the utility's marginal costs; it reduces wear on base load units caused by cycling them; and it reduces the likelihood of a capacity shortfall during the next peaking cycle.

2. <u>Rule 304(f) Is Not Limited to "Real-Time" Contracts</u>

Intervenors allege that Rule 304(f) does not apply to contracts where the avoided cost rate was pre-determined and fixed in the contract. *See* Idaho Wind Partners I, LLC, Guy, Direct, p. 5. Such an interpretation would make Rule 304(f) inapplicable to virtually all of Idaho Power's PURPA contracts. Mr. Guy asserts that such an interpretation is required by the following passage from Order No. 69:

> [FERC] does not intend that this paragraph *override* contractual or other legally enforceable obligations incurred by the electric utility to purchase from a qualifying facility. In such arrangements, the established rate is based on the recognition that the value of the purchase will vary with the changes in the utility's operating costs. These variations *ordinarily* are taken into account, and the resulting rate represents the average value of the purchase over the duration of the obligation. The occurrence of such periods *may* similarly be taken into account in determining rates for purchases.

Order No. 69, 45 Fed. Reg. at 12,228 (emphasis added). Mr. Guy has taken FERC's statement, above—which refers only to a sub-category of fixed-rate contracts—and incorrectly concluded that it applies equally to *all* fixed-rate contracts. *See* Commission Staff Rebuttal Test. R. Sterling at 4-5 (June 29, 2012) ("Mr. Guy's and Mr. Schoenbeck's interpretations of the proper application of Section 304(f) might be correct if the presumptions described by FERC in Order No. 69 and in the *Entergy* order [*Entergy Services, Inc.*, 137 FERC ¶ 61,199] were correct for Idaho. However, those presumptions, in fact are <u>not</u> correct for Idaho.").

A careful reading of the passage above makes clear that FERC is talking only about contracts with fixed rates that account for light load conditions contemplated by Rule 304(f). Several phrases in FERC's statement compel the conclusion that there are more than one type of fixed rate contracts and that FERC is only talking about one type: The word "ordinarily", in the third sentence, indicates that there are at least two types of contracts—the "ordinary" contracts, and non-ordinary contracts. "Ordinary" contracts, according to FERC, above, are those with rates that take into account the light load conditions contemplated by Rule 304(f). It follows, logically, that non-ordinary avoided cost contracts *do not* take into account the light load conditions contemplated by Rule

304(f). In the next sentence, above, FERC says that such light load periods "may" be taken into account in determining rates for purchases. The use of "may" as opposed to "shall" indicates FERC permits both types of contracts under PURPA. In the case of ordinary contracts—those that take Rule 304(f) conditions into account when setting the rate—allowing the utility to curtail a QF during circumstances described in Rule 304(f) would, in effect, give the utility two remedies for the same event. Therefore, the first sentence in the above indented quote clarifies FERC's position that Rule 304(f) curtailment of QF output in instances where the contract rate already takes Rule 304(f) conditions into account would impermissibly "override" the resolution of the issue embodied in the contract. *Pub. Serv. Co. of Okla. v. State*, 2005 OK 47, 56, 115 P.3d 861, 884 (2005) ("While we agree with the [Oklahoma] Commission that purchase rates may take periods of operational circumstances into account, thereby rendering moot the provisions of § 292.304(f), we agree with [the utility] that the record in this case does not provide substantial evidentiary support for the [Oklahoma] Commission's contention [that such operational circumstances are accounted for in the instant purchase rates]."). However, if a state chooses not to account for such effects when setting rates, then curtailment would not be duplicative, nor would it override the contract. Under such facts, curtailment is the only means left by which the utility may exercise its right under Rule 304(f) to prevent customers from having to bear such costs.

The *Entergy* order, cited on page 5 of Mr. Guy's Direct Testimony, does not alter this analysis or conclusion. In that order, FERC observed:

> *Many* avoided cost rates are calculated on an average or composite basis, and already reflect the variations in the value of the purchase in the lower overall rate. *In such circumstances*, the utility is already compensated, through

> the lower rate it generally pays for unscheduled QF energy, for any periods during which it purchases unscheduled QF energy even though that energy's value is lower than the true avoided cost. On the other hand, for avoided cost rates that are determined in real-time, such avoided costs adjust to reflect the low (or zero or negative) value of the unscheduled QF energy, allowing the QF to make its own curtailment decisions. In neither case is the utility authorized to curtail the QF purchase unilaterally.

Entergy Services, Inc., 137 FERC ¶ 61,199, P 56 (emphasis added). As in Order No. 69, the *Entergy* order uses words of limitation (italicized above) that make clear that FERC is speaking about a subset of contracts rather than the universe of QF-utility relationships. The *Entergy* order goes beyond Order No. 69 regarding yet another type of QF contract—those wherein the avoided cost is determined in real-time. FERC concludes that a utility may not unilaterally curtail QF output under either: (a) a fixed price contract that accounts for Rule 304(f) conditions, or (b) a real-time priced contract. However the *Entergy* Order, like Order No. 69, does nothing to limit Rule 304(f) as applied to contracts with long-term fixed rate prices that do not take into account circumstances contemplated in Rule 304(f).

Order No. 69 and the *Entergy* order make clear that Rule 304(f) does not permit a utility to curtail a QF with a fixed-price contract if the prices in the contract take into account light load conditions contemplated in Rule 304(f). However, those orders say nothing to limit the utility's right to curtail when fixed-rate prices have been calculated without accounting for such light load conditions. Intervenors' attempt to extend those orders to all QF contracts contradicts the plain language upon which they rely. Such an interpretation also would render meaningless the plain language of Rule 304(f)(1). *Mont. Air Chapter No. 29, Ass'n of Civilian Technicians, Inc. v. Fed. Labor Relations*

Auth., 898 F.2d 753, 761 (9th Cir. 1990) (citing *Bowles v. Seminole Rock & Sand Co.*, 325 U.S. 410, 89 L. Ed. 1700, 65 S. Ct. 1215 (1945), for the proposition that an agency's interpretation of its own rule must comport with the rule's language).

The distinction between contracts that *do* and contracts that *do not* take into account light load conditions contemplated in Rule 304(f) is critical, since according to Commission staff engineer, Rick Sterling, power purchase agreements in Idaho with published avoided cost rates *do not* take such conditions into account:

> I have been the person responsible for computing Idaho's published avoided cost rates for the past 18 years. Although I did not create the original SAR model used to compute published avoided cost rates, I have made the extensive changes to the model that have been ordered over the past 18 years, I have maintained the model, and I have been responsible for making all of the avoided cost computations adopted by the Commission since 1995. Based on my extensive experience with the SAR model, Idaho's published avoided cost rates <u>do not</u> already reflect the variations in the value of the purchase in the lower overall rate <u>during the specific low loading scenarios when 304(f) is clearly intended to apply</u>.

Sterling, Rebuttal, p. 5 (emphasis in original). Mr. Sterling goes on to explain that there are no post-model adjustments to avoided cost prices that take Rule 304(f) into account. Nor does the wind integration adjustment, the 90/110 performance band, the Mechanical Availability Guarantee, or any other step in the SAR model process provide for an adjustment to address Rule 304(f) costs. *Id.* at 9-13. Likewise, the AURORA model used by Idaho Power under its proposed IRP methodology does not in any way account for light load conditions in the way contemplated in Rule 304(f). Reading, Direct, Ex. 504, 41 (*Idaho Power Company's Response to the Second Production Request of the Commission Staff to Idaho Power Company,* Response to Request No. 6). Because Idaho Power's avoided cost rates do not take into account Rule 304(f), Idaho Power retains the right to curtail QFs under the circumstances contemplated in the rule. Intervenors' protests to the contrary are unpersuasive.

3. <u>Rule 304(f) Applies to Existing, Fixed-Price Contracts</u>

Intervenors argue, in the alternative, that Rule 304(f) at least cannot apply to *existing* QF contracts because doing so would change an established bargain. *See* Direct Test. Schoenbeck at 37 ("[Schedule 74] unilaterally modifies otherwise negotiated and existing contractual rights."); *see also* Guy, Direct, p. 6; Reading, Direct, p. 50. This argument runs counter to the principle that extant applicable law is a part of every contract as if it were expressly cited or its terms incorporated in the contract. *See Fidelity Trust Co. v. State*, 72 Idaho 137, 149 (1951) (finding "it is axiomatic that extant law is written into and made a part of every written contract."); *Pub. Serv. Co. of Okla.*, 2005 OK at 54, 115 P.3d at 884. In *Public Service Co. of Oklahoma v. State*, the Oklahoma Supreme Court applied this principle and found that a utility retained the right to curtail output under Rule 304(f) even though there was no provision in the QF contract expressly incorporating Rule 304(f):

> An intent to modify applicable law by contract is not effective unless the power is expressly exercised. A contractual adjustment of rights contrary to law must be clearly expressed in the agreement if applicable law is not to be applied. Hence, the provisions of § 292.304(f) remain available to [the utility] *regardless of whether they are expressly included in the contract.*

2005 OK at 54, 115 P.3d at 884. (internal citations omitted; emphasis added). The Oklahoma Supreme Court's opinion makes clear that Intervenors' assertion that extant law must be expressly *included* into a QF contract is wrong; extant law is part of every contract unless *excluded*, and QF contracts in Idaho do not exclude Rule 304(f). *See* Direct Test. Sterling at 38 ("I think Idaho Power has always had [Rule 304(f)] authority whether or not it is expressly spelled out in a contract or a tariff"); *see also* Sterling, Rebuttal, p. 13 ("none of the provisions contained in any of the Idaho Wind Partners' contracts (or any other QF contracts) address or capture variations in an overall rate that would encompass circumstances described in FERC Order No. 69 or in the *Entergy* order"). Therefore Idaho Power, like the utility in *Public Service Co. of Oklahoma v. State*, retains its right to curtail under Rule 304(f).

4. Idaho Power's Proposal to Implement Rule 304(f) with Schedule 74 Is Not Novel

Idaho Power's right to curtail QFs under Rule 304(f) conditions exists without any further action from the state. However, a tariff or other official statement of policy may improve the effectiveness of such curtailments, when the need arises. Nevada, California, and Florida have all implemented Rule 304(f) curtailment in a fashion similar to Schedule 74. These three states found it appropriate to clarify rights under Rule 304(f).

Possibly most similar to Schedule 74 is the Nevada Public Service Commission's ("Nevada PSC") implementation of Rule 304(f). *Saguaro Power Co. v. Nevada Power Co.*, Nevada PSC Docket No. 93-5037, 1994 WL 780897 (November 30, 1994) (implementing Rule 304(f) with respect to two pre-existing QF contracts which were later repealed as part of a settlement wherein the QFs and the utility amended their power purchase agreements.). In *Saguaro*, the Nevada PSC resolved a dispute over the utility's right to make a Rule 304(f) curtailment under two existing PPAs by providing a specific curtailment procedure. *Id.* at attachment "*Policy and Procedure for Curtailment of Certain PURPA Qualifying Facilities*" (appears in the record as Exhibit. No. 4 to Direct Testimony of Idaho Power witness Tessia Park) (the "*Nevada Procedure*"). The *Nevada Procedure* allows the utility to curtail on a *pro rata* basis the two QFs when accepting QF output would result in negative avoided costs. *Nevada Procedure* at P 3, 5. Negative avoided costs may arise when the utility is using only base load resources and is not making economy purchases. *Id.* at P 6. Base load resources are, *inter alia*, the utility's coal generation and the utility's allocation of the Hoover hydroelectric project, and resources required for system regulation. *Id.* at P 3. The *Nevada Procedure* also imposes notice and recordkeeping requirements on the utility. *Id.* at P 7.

In implementing standard offer PURPA contracts, the California Public Utilities Commission ("California PUC") provided that utilities could curtail QF purchases when avoided costs are negative. *Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities*, California PUC Decision 82-01-103, ordering paragraph 14, 8 CPUC2d 20, 1982 Cal. PUC LEXIS 1296 (Jan. 21 1982). Rather than defining base load resources, the California PUC provided an example of when negative avoided costs may occur:

> [I]f a base load or a large oil-fired intermediate load plant were shut down at night, due to an excess of QF electricity, but then could not be restarted and brought up to its rated output for the next day's peak load, and necessitated instead startup of a plant with very high generating costs (e.g., a gas turbine peaker or an expensive emergency purchase of capacity), the cost to meet the day's peak load might substantially exceed the avoided cost of the previous night's shutdown.

Id. at *100. The California PUC concluded that negative avoided cost did not occur merely because, to balance its system and accept QF output, a utility had to spill water it otherwise would have used to generate. *Id.* at *99-100. The California PUC limited curtailment to QFs of 1 MW or greater capacity. *Id.* at ordering paragraph 16. Although the California PUC expected curtailment circumstances were unlikely to occur in more than 100 hours per year, it did not place a limit on curtailment. *Id.* at *101. The

California PUC also imposed notice and recordkeeping requirements on the utilities. *Id.* at ordering paragraphs 15, 17.

The Florida Public Service Commission ("Florida PSC") approved the utility's curtailment plan as a reasonable means to deal with minimum load conditions that would have caused negative avoided costs. *In Re: Petition... curtailing purchase from qualifying utilities in minimum load conditions*, Order No. PSC-95-1133-FOF-EQ, 164 PUR4th 173, 1995 Fla. PUC LEXIS 1274, *28 (1995). Under the curtailment plan, minimum load occurs when utility generation plus QF generation plus other utility purchases are greater than demand. *Id.* at *3. The Florida PSC rejected the argument made by QFs that the utility should not be allowed to curtail during minimum load because minimum load resulted from poor planning by the utility. *Id.* at *11. The Florida PSC found that "lower than projected minimum load growth, and greater than projected QF capacity, created [the utility's] minimum load problem." *Id.* The Florida PSC explained how to determine whether avoided costs are negative:

> We find that a utility should consider all of the costs to generate electricity with and without QFs, including fuel cost, O&M, variable operating costs, unit shut-down and start-up costs, replacement power costs, incremental unit impact costs, and transmission losses, to determine whether negative avoided costs would occur during a minimum load condition.

Id. at *17 (incremental unit impact costs mean the increased operation and maintenance costs of cycling base load coal units). The utility procedure imposes four measures it must take prior to curtailing QFs: (1) minimize off-system energy purchases; (2) maximize economic off-system sales; (3) make maximum use of voluntary QF output reductions; and (4) reducing its own units to minimum reliable generation levels. *Id.* at

*20. If curtailment is needed despite the utility's mitigation efforts, non-firm QFs are curtailed first and, if necessary, firm QFs are curtailed. *Id.* at *25-26. QFs with firm capacity contracts are paid the capacity portion of rate during curtailment. Id. at *26. The utility's procedure provides for advance notice of curtailment to QFs. *Id.* at *19.

Nevada, California, and Florida have each implemented written procedures describing how Rule 304(f) is applied. The differences between them illustrate that States have flexibility to determine how Rule 304(f) is implemented so long as implementation is not inconsistent with the Rule. Schedule 74's features are similar in breadth and detail to written procedures adopted in Nevada, California, and Florida. Implementing Schedule 74 to address light load curtailments is a progressive, but by no means unprecedented, mechanism for implementing FERC Rule 304(f).

5. Idaho Power's Proposed Schedule 74 Comports with PURPA

Idaho Power has proposed Schedule 74 to establish the terms and conditions under which Idaho Power will exercise Rule 304(f) curtailment rights. Schedule 74 will apply whenever the utility is confronted with the choice during low load periods of curtailing QF output or not curtailing QFs and thereby causing Idaho Power to meet the next peak or peaks with a more expensive resource, such as a less efficient gas peaking unit. The specific requirements of Schedule 74 are tailored to comply with Rule 304(f).

a. "Base Load Resources" - Schedule 74 defines "Base Load Resources" to clarify which Idaho Power resources may remain on-line during a Rule 304(f) curtailment. Base Load Resources include Idaho Power's coal-fired generating resources, its run-of-river hydro generators, its Hells Canyon hydroelectric complex, and its Langley Gulch combined-cycle combustion turbine plant (when operable). Each of these resources is discussed below.

Coal-Fired Resources - Idaho Power operates coal-fired generating units at Jim Bridger, Valmy, and Boardman. These units require several days to restart each time they are shut down. Park, Rebuttal, p. 6. Because these units cannot be curtailed during light load periods and restored in time to meet subsequent peaks, Idaho Power will curtail QF generation prior to curtailing each of its coal-fired units.

Run-of-River Hydro Resources - Idaho Power must curtail QFs prior to run-of-river hydro generators during Rule 304(f) conditions because such facilities have license or permit requirements that prevent them from spilling water for the purpose of not generating. Park, Direct, p. 20 ("Pursuant to the FERC licenses Idaho Power has for its run-of-river hydro electric projects, the Company is obligated to take whatever generation flows through them; it does not have the ability to decrease or increase the generation."); Reading, Direct, Ex. 504, 11 (*Idaho Power Company's Response to the Second Production Request of Exergy Development Group of Idaho to Idaho Power Company*, at 22) ("The proposed operations in the applications for FERC licenses and state water quality certifications did not include spill except when flows exceeded plant capacity or when generators tripped off-line in emergency situations. To the contrary, operations may require an amendment to the FERC licenses and/or state water quality certifications.").

Hells Canyon Complex - Idaho Power must curtail QFs prior to reducing the Hells Canyon Complex generation below approximately 350 MW in order to comply with its FERC license and other regulatory and reliability requirements.

Applicable requirements include instantaneous and 3-day average minimum flows at each project, total dissolved gases ("TDG") limitations below each project; and North American Electric Reliability Corporation ("NERC") and Western Electric Coordinating Council ("WECC") system reliability criteria. These requirements are summarized on pages 24-27 of *Idaho Power Company's Response to the Second Production Request of Exergy Development Group of Idaho to Idaho Power Company.* Direct Test. Reading, Ex. 504, 13-16.

<u>Langley Gulch</u> - Idaho Power will curtail QFs prior to reducing Langley Gulch generation below its minimum generation level (approximately 160 MW[4]). Idaho Power cannot take Langley Gulch down to 0 MW during light load periods because Langley Gulch must run at about 160 MW in order to provide system regulation. Rebuttal Test. Park at 8 ("However, although Langley Gulch has the ability to ramp up and down, there are still limitations on taking it off-line during low loading periods. To ensure its availability to ramp when the variable intermittent resources drop or fall off, Langley Gulch will need to be on-line and running at minimum loadings during some periods, making it a 'must run' resource, in order to provide the regulation service and other ancillary services required by [NERC] mandatory reliability standards"). Idaho Power, like most other utilities, requires a load-following generator(s) to balance the difference between its base load generators and system load. Historically, Idaho Power used the Hells Canyon Complex for this function. However the potential load fluctuation of unscheduled energy on Idaho Power's system will soon exceed the regulation capabilities of the Hells Canyon Complex. Park, Direct, p. 12-14. When Langley Gulch

[4] Reading, Direct, Ex. 504, 17 (*Idaho Power Company's Response to the Second Production Request of Exergy development Group of Idaho to Idaho Power Company*, at 28, Response to Request for Production No. 21).

comes on line, one of its vital roles will be to supplement system regulation currently provided by the Hells Canyon Complex. Curtailment of Langley Gulch during light load conditions would compromise Idaho Power's ability to regulate large fluctuations in system load. Therefore, Idaho Power classified Langley Gulch as a Base Load Resource in Schedule 74. Park, Rebuttal, p. 8.

Some Intervenors have objected to Idaho Power defining non-coal units as Base Load Resources.[5] Those objections read Rule 304(f) too narrowly. Rule 304(f) cannot be read so narrowly as to require the utility to curtail all resources except slow ramping thermals. Such an interpretation likely would cause a system emergency because the thermal base-load units are not able to perform the essential function of ramping up and down quickly to keep loads and resources in constant balance. Such an interpretation would also cause Idaho Power to violate FERC licenses and other regulations which limit its legal ability to turn off generation at its hydroelectric power plants. Other state commissions have recognized that Rule 304(f) does not require curtailment of all non-coal resources. New York permits utilities to include nuclear plants, must-run fossil units, and run-of-river hydro. *Proceeding on Motion of the Commission to Establish Conditions Governing Curtailment Clauses in Contracts for On-Site Generation,* New York Public Service Commission Case No. 88-E-081, 1989 N.Y. PUC LEXIS 71 (July 27, 1989). Nevada allowed long-term take or pay, non-dispatchable contracts, test energy, and resources required for system regulation. *Nevada Procedure* at P 3. Montana found that Rule 304(f) may be triggered even though the utility is purchasing power, provided the purchased power contract met certain conditions. *In the Matter of the Petition of NorthWestern Energy for a Declaratory Ruling on the Applicability of 18*

[5] *See* Schoenbeck, Direct, p. 42; *see also* Looper, Direct, p. 5.

C.F.R. § 292.304(f) and ARM § 38.5.1903(1) to Contracts with Qualifying Facilities, Montana PSC Order No. 7172, 2011 PUC LEXIS 51 (Sept. 1, 2011), order on reh'g, Order No. 7172a, P 8-9, 2011 Mont. PUC LEXIS 57 (October 13, 2011) ("*NorthWestern*"). In sum, it is common practice for utility commissions to allow continued operation of non-base load thermal resources during Rule 304(f) curtailments. Schedule 74 clarifies which resources must run during Rule 304(f) curtailment events due to legal, safety, or system reliability related requirements, and reasonably implements Rule 304(f).

b. "Applicable QFs" - Schedule 74 applies to all QFs with nameplate capacity over 10 MW with Generator Output Limiting Controls (GOLCs) ("Applicable QFs"). Idaho Power chose not to curtail QFs without GOLCs during Rule 304(f) conditions because such QFs cannot be dispatched within a 1-hour period, and therefore could not be relied upon by Idaho Power when it seeks to reduce generation. Direct Test. Park at 26. Furthermore, the contribution of such QFs to the surplus of QF generation during Rule 304(f) events is believed to be negligible. Park, Direct, p. 26. The choice is reasonable given the reasons articulated above. Idaho Power has created two classes of QFs based on objective plant characteristics relevant to their ability to alleviate Rule 304(f) conditions. All QFs belonging to the same class are treated equally under the Schedule. Rule 304(f) (unlike Rule 307) does not mandate that QF curtailment occur in a nondiscriminatory basis. *C.f.* 18 CFR § 292.307 (During a system emergency, sales to QFs may be discontinued, provided "such discontinuance is on a nondiscriminatory basis.") To the contrary Rule 304(f)(2), which states in part that a utility invoking Rule 304(f) curtailment must notify "each affected qualifying facility", assumes that Rule 304(f) curtailment does not apply to all QFs. Under these conditions, exempting QFs that are under 10 MW or do not have GOLC capability is reasonable.

c. ***Notice*** - Rule 304(f)(2) requires a utility invoking the rule to notify each affected QF in time for the QF to cease the delivery of energy or capacity to the utility. Such notice shall be in accordance with State law or regulation. Rule 304(f)(2). Because Idaho Power only proposes to curtail QFs with GOLC capability, one-hour notice is sufficient for a QF to cease delivery. However, because QFs have an interest in knowing about curtailments further in advance, Schedule 74 obligates Idaho Power to use commercially reasonable efforts to provide such notice as soon as reasonably possible. Idaho Power intends to comply with this requirement by providing notice to QFs on a day-ahead basis, updated no later than one hour before curtailment, if the need to curtail changes. Park, Direct, p. 25. Rule 304(f)(3) provides that any utility which fails to comply with the notice provisions of paragraph 304(f)(2) pay the QF for generation and capacity as though a light load period had not occurred. Idaho Power understands that this remedy would be available to QFs regardless of whether or not such remedy is set forth in Schedule 74.

d. ***Verification*** - Rule 304(f)(4) provides that the utility's claim that a light load condition contemplated in Rule 304(f) has occurred (or will occur) is subject to verification by the Idaho Commission before or after the occurrence as the State determines necessary or appropriate.

> A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority

determines necessary or appropriate, either before or after the occurrence.

Rule 304(f)(4). Schedule 74 attempts to accommodate this requirement by setting forth Idaho Power's obligation to maintain records of loads and outputs from all units prior to, during, and after each period of curtailment. Schedule 74 also requires Idaho Power, at the end of each curtailment period, to notify all curtailed QFs of the duration of the curtailment.

e. ***Off-System Sales*** - Intervenors allege that Idaho Power should pursue off-system sales before invoking Rule 304(f) to curtail QFs. Schoenbeck, Direct, p. 42. While Idaho Power may make sales where the opportunity presents, such sales should not be required as a condition to curtailing QFs under Rule 304(f). QFs do not deliver pursuant to any enforceable energy schedule, and consequently Idaho Power cannot sell the energy ahead of time. Idaho Power receives no schedule for intermittent QFs and therefore does not know how much energy it will have available to sell. This makes advance sales virtually impossible. Park, Direct, p. 9. If Idaho Power were to attempt to sell surplus QF output, it many times would not find a market due to regional energy glut conditions. *Id*, at 8-9. Idaho Power is aware that other State Commissions have insisted on the utility maximizing off-system sales prior to implementing Rule 304(f) curtailment. *See eg., Saguaro Power Co. v. Nevada Power Co.,* Nevada PSC Docket No. 93-5037, 1994 WL 780897; *In Re: Petition ... curtailing purchase from qualifying utilities in minimum load conditions,* Order No. PSC-95-1133-FoF-EQ 164 PUR 4th 173, 1995 Fla. PUC LEXIS 1274. However, those decisions predate FERC's unbundling of the bulk transmission system. Unbundling has complicated the task of selling economy energy since the utility must undesignate the network resource status of the source of such sales. Park, Direct, p. 10. All of the factors, above, make sale of surplus generation during Rule 304(f) conditions an unworkable option for Idaho Power.

f. Economic Impact - Intervenors allege that Schedule 74 should be rejected because it could have unacceptable economic consequences on their existing projects. *See* Guy, Direct, p. 6. Intervenors attempt to insert a limitation that does not exist in the rule. However, nothing in Rule 304(f) suggests that economic impact to the QF should limit a utility's Rule 304(f) rights. If Idaho Power were to propose or accept such a cap, Idaho Power would, in effect, be modifying the avoided cost by foregoing potential savings in excess of the cap. In any event, because the level of Rule 304(f) curtailment anticipated by Idaho Power is minimal in comparison to the QF's total PPA revenues, the essence of Intervenors' assertions—that Schedule 74 will threaten the viability of existing projects—is unfounded.

g. Schedule 74 Does Not Repeat Fatal Errors of NorthWestern Energy's Proposed Curtailment Tariff in Montana - Montana recently rejected a utility proposal to curtail QFs ostensibly under circumstances contemplated in Rule 304(f). *NorthWestern*, Order Nos. 7172, 7172a. Intervenors' witness, Don Reading, alleges that the *NorthWestern* orders identify two problems with Idaho Power's proposed Schedule 74. First, he argues that the Montana Commission correctly rejected NorthWestern's proposal because Rule 304(f) is narrower than NorthWestern believed it to be. Reading, Direct, p. 57. Second, he notes that NorthWestern's proposal, unlike Idaho Power's, faithfully incorporated the remedy for failure to provide a QF with proper advanced notice set forth in Rule 304(f)(3). *Id.* Mr. Reading's allegations are unpersuasive. As explained previously, the fact that Idaho Power did not expressly incorporate Rule 304(f)(3) into Schedule 74 does not render it ineffectual because Schedule 74 is not controlling as between it and the FERC Rules. *See NorthWestern* Order No. 7172a at P 11 (stating that NorthWestern's QF-1 tariff does not trump FERC and state rules). Mr. Reading's other point, that Northwestern's rule is broader than allowed by Rule 304(f), has no bearing on the different and distinct provisions of Schedule 74. NorthWestern's proposed curtailment tariff would have allowed it to curtail QF generation *any time such generation would increase its system costs.* The Montana PSC found that such a rule "far exceeds the scope of [Rule 304(f)]." *NorthWestern* Order No. 7172a at P 6. Schedule 74 contains no analogous provision. Schedule 74 allows curtailment only during light load periods when QF generation would cause baseload resources to be unavailable during ensuing peak periods and Idaho Power must replace those resources with more expensive thermal peaking units. Schedule 74 is fully consistent with Rule 304(f).

h. Schedule 74 Better Implements Rule 304(f) Than Having No Schedule - Finally, Intervenors provide no meaningful alternative to Idaho Power's Schedule 74. Staff agrees with Idaho Power that Rule 304(f) has always been available to the utilities and exists whether or not the Commission approves Schedule 74. Sterling, Direct, p. 38. Even Dr. Reading appears to admit that Rule 304(f) would apply under the right circumstances. *See* Reading, Direct, p. 52 ("[Rule 304(f)] would apply if the utility had to instead meet the next peak with a more expensive peaking resource, such as a less efficient gas peaking unit."). If the question is whether Idaho Power should invoke Rule 304(f) with a Schedule or without one, implementing the Rule through a Schedule has several advantages. It provides clear notice to QFs of the existence of Idaho Power's Rule 304(f) rights. It provides the algorithm for determining when Rule 304(f) conditions are present. And it sets forth Idaho Power's duties to the QF during such conditions. All of the above will improve efficiency in implementing Rule 304(f) and reduce disputes between Idaho Power and the QFs regarding whether Rule 304(f) has been implemented correctly. For all the reasons above, Idaho Power Schedule 74 should be allowed to take effect.

E. ***THE COMMISSION SHOULD DETERMINE THAT UTILITY PURCHASERS OF QF GENERATION OWN RENEWABLE ENERGY CREDITS ASSOCIATED WITH THAT GENERATION***

Idaho Power asks the Commission declare that when a utility is compelled to purchase QF output under the PURPA must-buy obligation, the environmental attributes associated with the QF output remain bundled with the QF energy and capacity and the purchasing utility is therefore the owner in the first instance of any RECs that subsequently may be associated with the QF output. This result is permissible under PURPA; indeed, FERC has held that the ownership of RECs is controlled by state law not by PURPA. *American Ref-Fuel Co.*, 105 FERC ¶ 61,004, P 23 (2003), reh'g denied, 107 FERC 61,016 (2004), *appeal dismissed sub nom., Xcel Energy Servs. v. FERC*, 407 F.3d 1242 (D.C. Cir. 2005). This result also prevents QFs from taking advantage of ambiguity or uncertainty under Idaho law to unilaterally lay claim to RECs. This result also recognizes the reality that the utility and its customers are purchasing renewable generation. Finally, this result recognizes that states create RECs and that the value of RECs associated with energy sold under a PURPA contract should appropriately be retained fo rhte benefit of the customers that must purchase that generation—a result that better serves the public interest.

Approximately 25 states and the District of Columbia have enacted renewable portfolio standards ("RPS"). Utilities in states with an RPS must obtain a designated percentage of their annual energy needs from renewable energy sources. About half of RPS states provide for compliance through use of renewable energy credits ("RECs"). In general, a REC represents the "environmental attributes" associated with 1 MWh of electricity generated by a renewable energy resource. *See Grand View PV Solar Two, LLC v. Idaho Power Company*, IPUC Case No. IPC-E-11-15, Order No. 32580, 4 (June 21, 2012) (citing *In the matter of a Petition filed by Idaho Power Co. for an Order Determining Ownership of the Environmental Attributes Associated with Qualifying Facility Upon Purchase by a Utility of the Energy Produced by a Qualifying Facility*, IPUC Case No. IPC-E-04-2, Order No. 29480 (2004); *In the Matter of the Application of Idaho Power Co. for Authority to Retire its Green Tags*, IPUC Case No. IPC-E-08-24, Order No. 32002 (2010)).

Idaho does not have an RPS program. *Grand View PV Solar Two, LLC*, Order No. 32580 at 5 ("[T]he Idaho Legislature has considered but not adopted an RPS."). Idaho's QFs and utilities are nevertheless interested in owning the environmental attributes or RECs associated with the power that they generate or purchase in the state. Such attributes or RECS may have value through selling them to utilities in need of RECs in states with active RPS programs.[6] Moreover, if a state or federal RPS is

[6] One way to currently monetize and sell environmental attributes associated with energy generated or purchased in Idaho would be to register those attributes as RECs with the Western Renewable Energy Generation Information System ("WREGIS"). According to its website, WREGIS "is an independent, renewable energy tracking system for the region covered by the Western Electricity Coordinating Council

adopted, such attributes or RECs may have direct compliance value to Idaho Power and its customers.

The parties have asked the Commission to determine who owns RECs in Idaho when a QF generates renewable energy and compels an Idaho utility to purchase that energy under the PURPA must-buy obligation. In general, QF developers ask the Commission to conclude that QFs own the RECs,[7] and the utilities ask the Commission to conclude that utilities own the RECs.[8] Commission staff has recommended that the RECs be owned by the utilities but has suggested that the avoided cost price paid by utilities for QF power may need to be augmented (increased) under the SAR methodology, but not the IRP methodology, in order to ensure that QFs are adequately compensated for the transfer of RECs.[9] For the reasons set forth below, Idaho Power urges the Commission to recognize its inherent authority to determine ownership of RECs in the absence of any Renewable Portfolio Standard (RPS) program or REC program adopted by the Idaho legislature, to recognize the need to decide REC ownership in Idaho now, and to recognize the compelling reasons why RECs from utility

("WECC") [which includes Idaho]. WREGIS tracks renewable energy generation from units that register in the system using verifiable data and creates renewable energy credits (RECs) for this generation. WREGIS Certificates can be used to verify compliance with state and provincial regulatory requirements (Renewable Portfolio Standards, for example) and in voluntary market programs." *See* http://www.wregis.org/.

[7] *E.g.*, Reading, Direct, p. 59-60.

[8] *See* Clements, Direct, p. 7 ("Environmental Attributes generated by a QF project should go to the utility whenever that QF sells energy to the utility and receives compensation for that energy at approved avoided cost rates."); Kalich, Rebuttal, p. 9 ("[T]o the extent the Commission chooses to assign RECs to utilities, Avista opposes adjusting (i.e., increasing) avoided cost rates in exchange for obtaining the RECs."); Stokes, Rebuttal, p. 42-43 ("Idaho Power, similar to other parties to this docket, requests that the Commission specifically find that the Environmental Attributes or RECs from utility purchased QF generation are owned by the purchasing utility.").

[9] IPUC Staff Direct Test. R. Sterling at 46-47 ("[T]he cost of RECs would, already be accounted for in computing avoided cost rates using the IRP methodology. ... Under the SAR methodology, however, ... some adjustment to the avoided cost rates may be necessary.").

purchased QF generation in the state of Idaho should be determined to be owned in the initial instance by the purchasing utility.

1. States Have the Authority to Decide the Ownership of RECs

It is well established that the question of REC ownership is properly decided by the states. PURPA does not govern the question, even when the renewable energy in question is sold pursuant to the PURPA must-buy obligation. *American Ref-Fuel Co.*, 105 FERC ¶ 61,004, P 23 (2003) ("*American Ref-Fuel I*"), reh'g denied, 107 FERC ¶ 61,016 (2004) ("*American Ref-Fuel II*"), *appeal dismissed sub nom., Xcel Energy Servs. v. FERC*, 407 F.3d 1242 (D.C. Cir. 2005) ("States, in creating RECs, have the power to determine who owns the REC in the initial instance, and how they may be sold or traded; it is not an issue controlled by PURPA"); *Wheelabrator Lisbon, Inc. v. Conn. Dept. of Util. Control*, 531 F.3d 183, 190 (2nd Cir. 2008) (affirming that "state law governs the conveyance of RECs."); *Morgantown Energy Assoc.*, 139 FERC ¶ 61,066, P 46 (2012) ("PURPA does not address the ownership of RECs ... states have the authority to determine ownership of RECs in the initial instance, as well as how they are transferred from one entity to another."); *Grand View PV Solar Two, LLC*, Order No. 32580 at 14 ("RECs are created by the states and exist outside the confines of PURPA.").

These principles were first articulated by FERC in 2003 in response to a petition for declaratory order filed by American Ref-Fuel and three other QF owners. The QFs asked FERC for an order declaring that avoided cost contracts entered into pursuant to PURPA do not inherently convey RECs to the purchasing utility (absent an express contract provision to the contrary). *American Ref-Fuel I,* 105 FERC ¶ 61,004, P 2. In response, FERC issued a declaratory order concluding:

> (1) "States, in creating RECs, have the power to determine who owns the RECs in the initial instance, and how they may be sold or traded; it is not an issue controlled by PURPA." *Id.* at P 23. "While a state may decide that a sale of power at wholesale automatically transfers ownership of the state-created RECs, that requirement must find its authority in state law, not PURPA." *Id* at P 24.
>
> (2) "[C]ontracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility (absent an express provision in the contract to the contrary)." *Id.*
>
> (3) "[A]voided cost rates . . . are not intended to compensate the QF for more than capacity and energy." *Id.* at P 22. "[A]voided cost rates . . . do not convey the RECs, in the absence of an express contractual provision." *Id.* at P 18.

A number of utilities requested rehearing. On April 15, 2004, FERC issued an order denying rehearing. *American Ref-fuel II,* 107 FERC 61,016. FERC noted that its reference to "express contractual provision" in the 2003 declaratory order seems to have been misunderstood. *Id.,* at P 6, n.1. FERC is referring to its statement that a PURPA contract does not convey RECs "absent an express provision to the contrary in the contract" and to its statement that avoided cost rates do not convey RECs "in the absence of an express contractual provision." In the order denying rehearing, FERC clarifies: "All we intended by this language was to indicate that a PURPA contract did not inherently convey any RECs, and correspondingly that, assuming State law did not provide to the contrary, the QF by contract could separately convey the RECs." *Id.*

This clarification is critical. As explained by the United States Court of Appeals for the Second Circuit, it means that "*American Ref-Fuel* does not stand for the proposition that PURPA requires an express contractual provision in order for RECs ... to be transferred to a public utility pursuant to a PURPA contract ...." *Wheelabrator Lisbon, Inc.*, 531 F.3d at 189 (quoting and affirming *Wheelabrator Lisbon, Inc. v. Connecticut Dept. of Pub. Util. Control*, 526 F. Supp. 2d 295, 306 (D. Conn. 2006)).

In light of the clarification made in *American Ref-Fuel II* and explained by the Second Circuit in *Wheelabrator*, FERC's conclusions regarding RECs and PURPA transactions may be summarized as follows:

> (1) States determine initial ownership of RECs and how RECs may be sold or traded. PURPA does not control the question. The State determination must be based on state law not PURPA.
>
> (2) PURPA contracts do not inherently convey RECs to the purchasing utility. However, a PURPA sale may transfer RECs if the PURPA contract so provides or if transfer of RECs to the utility is a consequence of the State's law on ownership of RECs.
>
> (3) Avoided cost rates are not intended to compensate the QF for more than capacity and energy. Payment of avoided cost rates does not inherently convey RECs to a utility. However, RECs may transfer to the utility upon payment of avoided cost if the PURPA contract so provides or if transfer of RECs to the utility is a consequence of the State's law on ownership of RECs.

FERC's decision to deny rehearing of *American Ref-Fuel* was appealed to the United States Court of Appeals for the District of Columbia Circuit. The Court found that it lacked jurisdiction to review FERC's declaratory order. The Court noted that FERC "has in effect merely announced the position it would take in any future enforcement action" and the Court stated that FERC's declaratory order "is of no legal moment unless and until a district court adopts that interpretation when called upon to enforce PURPA." *Xcel Energy Services, Inc.*, 407 F.3d at 1244. The Court concluded: "FERC's position is reviewable by this court only after someone—a utility, a QF, or the Commission—brings an enforcement action in the district court and appeals therefrom." *Id.*

For the reasons discussed by the D.C. Circuit Court, FERC's determinations in *American Ref-Fuel* are merely advisory at present. However, *American Ref-Fuel* provides compelling evidence of the position FERC can be expected to take in any enforcement action. Moreover, FERC's conclusion—that states decide ownership of RECs and that PURPA does not govern REC ownership—has been widely adopted by state commissions, state courts, and the federal court. *See, e.g., Wheelabrator*, 531 F.3d at 184; *In the Matter of the Ownership of Renewable Energy Certificates*, 913 A.2d 825 (N.J. Super. Ct. App. Div. 2007) (the New Jersey court of appeals affirmed a state utility commission's exercise of authority to determine the ownership of RECs); *ARIPPA v. Penn. PUC*, 966 A.2d 1204, 1211 (Pa. Commw. Ct. 2009) (the Pennsylvania court of appeals noted that FERC in *American Ref-Fuel*, the U.S. Court of Appeals for the Second Circuit in *Wheelabrator*, and the New Jersey court of appeals in *In re Ownership of RECs*, have all affirmed a state's authority to determine the ownership of RECs, and the Pennsylvania court agreed that PURPA does not preempt a state commission's authority to determine the ownership of RECs); *City of New Martinsville*, Nos. 11-1738, 11-1739, 2012 W. Va. LEXIS 308, at *16-17 (W. Va. June 11, 2012) (Supreme Court of West Virginia upheld the state utility commission's determination that utility owned RECs associated with power sold under a PURPA contract and cited with approval to FERC's reasoning in *American Ref-Fuel* that ownership of RECs is a state determination not governed by PURPA).

Significantly, the Idaho Commission recently agreed with FERC that states decide initial ownership of RECs and that PURPA does not control the question. *Grand View PV Solar, LLC,* Order No. 32580 at 14 ("RECs are inventions of state property law. FERC has consistently held that PURPA does not control the ownership of RECs. More to the point, RECs are created by the states and exist outside the confines of PURPA (with the exception of express provisions in a PPA). (internal citations omitted).

In sum, it appears that FERC, numerous state commissions, the United States Court of Appeals for the Second Circuit, the Connecticut Supreme Court, the West Virginia Supreme Court, the court of appeals in Pennsylvania, the court of appeals in New Jersey, and the Idaho Commission all agree that ownership of RECs is decided by states even in the context of a PURPA power sale. Idaho Power is not aware of any decision in any jurisdiction suggesting that states do not have the authority to determine ownership of RECs as an initial matter.

2. The Commission Has the Subject-Matter Jurisdiction to Decide Ownership of RECs from PURPA Sales Even in the Absence of an Idaho RPS Statute

As discussed in the preceding section, states have the power to decide who owns environmental attributes or RECs in the first instance. This decision can be made legislatively by statute. or it can be made administratively by order of a state utility commission. However, utility commissions only have the powers delegated to them by statute. Before a utility commission can administratively determine the ownership of RECs, it must have the statutory authority or subject-matter jurisdiction to do so.

All state utility commissions have broad general powers enumerated in the commission's organic or enabling statutes. These powers may be sufficient to authorize a commission to determine ownership of RECs. In addition to these organic or enabling powers, some states have passed RPS legislation, which may grant their state utility commission additional statutory authority to regulate ownership of RECs.

Even when the legislature passes an RPS and addresses ownership of RECs generally, there may be questions of ownership that are not addressed by the RPS legislation. For example, most RPS legislation fails to state whether the utility or the QF owns the RECs for renewable energy purchased under a PURPA contract that pre-dates the passage of the RPS statute. Under such circumstances, many utility commissions have made an administrative determination of REC ownership (most, perhaps all, commissions have determined that the RECs are owned by the utility under such circumstances). Edward A. Holt et al., *Who Owns Renewable Energy Certificates? An Exploration of Policy Options and Practice*, at xiv (Ernest Orlando Lawrence Berkeley National Laboratory 2006); *see also infra* n. 10-11 (discussing the aforementioned report).. In making such an administrative determination of REC ownership, state commissions are concluding that they have subject-matter jurisdiction.

The Pennsylvania utility commission has found subject-matter jurisdiction to decide REC ownership based on the combined effect of the state RPS statute and the commission's organic statutes. *Petition for a Declaratory Order Regarding the Ownership of Alternative Energy Credits*, Penn. PUC P-00052149, 2006 Pa PUC LEXIS 110, at *48-56 (2006). The Pennsylvania court of appeals has upheld this finding of subject-matter jurisdiction. *ARIPPA*, 966 A.2d at 1212.

The West Virginia utility commission has found that it has subject-matter jurisdiction to determine REC ownership on the separate and independent grounds of both the state RPS statute and the commission's organic statutes. *Monongahela Power Co.*, W. Va. PSC Case No. 11-0249-E-P, 2011 W. Va. PUC LEXIS 2760, at *43 (2011). The West Virginia commission reasoned:

> We determine that the Legislature has vested the Commission with jurisdiction and authority over this matter. Not only does the Commission have subject-matter jurisdiction over this matter and the parties based on the Portfolio Act [the State of West Virginia's RPS statute], the Commission also has jurisdiction over this matter pursuant to the provisions of Chapter 24 of the West Virginia Code [the Commission's organic enabling act] related to the Commission's powers and duties to regulate public utilities, to establish just and reasonable rates . . . and to review and approve [power purchase agreements]. *Id.*

The West Virginia Supreme Court affirmed the commission's decision to award REC ownership to utilities but the court did not address subject-matter jurisdiction (presumably because jurisdiction was not raised on appeal). *City of New Martinsville*, 2012 W. Va. LEXIS 308.

The Connecticut utility commission appears to have found that it has subject-matter jurisdiction to determine REC ownership on the basis of its organic statutes alone even though Connecticut also has an RPS statute. *Wheelabrator Lisbon, Inc. v. Dep't of Pub. Util. Control*, 931 A.2d 159, 171 (Conn. Sup. Ct. 2007) ("We see no reason to conclude that the department lacked jurisdiction to make these determinations under [statutes providing for declaratory orders] merely because the certificates were created and § 16-245a, which recognized and gave value to the certificates, was enacted after the execution of the 1991 agreement."). The Connecticut courts have upheld the commission's finding of jurisdiction without resort to the state RPS statute.

Wheelabrator Lisbon, Inc. v. Dep't of Pub. Util. Control, 2006 Conn. Super. LEXIS 858, at *12-14 (Conn. Super. Ct. 2006), aff'd *Wheelabrator Lisbon, Inc.,* 931 A.2d at 167-171.

Finally, the Wyoming utility commission has exercised subject-matter jurisdiction to decide REC ownership on the basis of its organic statutes alone and in the absence of a state RPS statute. *See In the Matter of the Application of Rocky Mountain Power to Implement a Permanent Avoided Cost Methodology*, Wyo. PSC Docket No. 20000-388-EA-11, Record No. 12750, P 50, 2011 Wyo. PUC LEXIS 441 (2011) (Commission discussed its various powers under its organic statutes and noted that "[r]ead in *pari material*, these statutes articulate the basic mechanism of the public interest standard which the Commission is to follow in its decisions."). The Wyoming Public Service Commission held that RECs arising from the sale of renewable QF power under a PURPA contract are owned by the purchasing utility. *Id.* at P 63 ("... the Commission finds [the utility] should continue to retain the RECs since they represent tangible value for the ratepayer, and they should not be routinely severed from the underlying green power generated."). To date, the Wyoming commission's exercise of jurisdiction has not been subjected to judicial review.

These cases indicate that state commissions enjoy subject-matter jurisdiction to decide the ownership of RECs even in the absence of a state RPS. Indeed, the West Virginia, Connecticut, and Wyoming commissions all concluded that a state utility commission's organic statutes are sufficient on their own, and without support from a state RPS statute, to establish a commission's subject-matter jurisdiction to determine the ownership of RECs.

The Idaho Legislature has not enacted an RPS statute or otherwise made an express grant of authority to the Idaho Commission to determine the ownership of RECs. Moreover, the Idaho Commission "exercises limited jurisdiction and has no authority other than that expressly granted to it by the legislature." *Alpert v. Boise Water Corp.*, 118 Idaho 136, 140 (1990). The Idaho Supreme Court has further explained:

> The Commission . . . exercises a limited jurisdiction and nothing is presumed in favor of its jurisdiction. As a general rule, administrative authorities are tribunals of limited jurisdiction and their jurisdiction is dependent entirely upon the statutes reposing power in them and they cannot confer it upon themselves, although they may determine whether they have it.

Wash. Water Power Co. v. Kootenai, 99 Idaho 875, 879 (1979) (internal citations omitted).

Nevertheless, through the Commission's organic statutes—the public utility laws (Chapters 1-7 of Title 61, Idaho Code)—the Idaho Legislature has established a "comprehensive scheme for the regulation of investor-owned public utilities ...." *Alpert*, 118 Idaho at 140. More specifically, the authority granted to the Commission includes:

> [T]he power to investigate and fix rates and regulations, I.C. § 61-503; determine the reasonableness of rates, I.C. § 61-502; investigate proposed interstate rates, I.C. § 61-506; determine rules and regulations affecting the performance of public utilities, I.C. § 61-507; order improvements to utility facilities, I.C. § 61-508; investigate accidents occurring on public utility property arising from its maintenance or operation, I.C. § 61-517; determine standards and practices for the measurement of quantity, quality or other conditions pertaining to the supply of a public utility product or service, I.C. § 61-520; ascertain the value of public utility property, I.C. § 61-523; and issue certificates of convenience and necessity, I.C. § 61-526.

Id., at 140, n.1. Regarding the extensive range of powers granted to the Commission, the Idaho Supreme Court has noted:

> There is no question that much of the work of the Commission, particularly in the areas of ratemaking, requires expertise, technical skill and constant attention. . . . Such was held to be a strong argument for the delegation of the legislative authority to a commission under statutes established by the legislature.

Wash. Water Power Co., 99 Idaho at 882.

The Idaho Supreme Court has recognized that the Idaho Commission has the authority to approve the terms and conditions of PURPA contracts but that the subsequent interpretation and enforcement of contracts generally does not fall within the Commission's powers. *Idaho Power Co. v. Cogeneration, Inc.*, 129 Idaho 46, 49 (1996).

Under Idaho Code § 61-328, a public utility may not transfer utility property without the approval of the Commission. *See e.g., In the Matter of the Application of Idaho Power Company for Authority to Sell to PacifiCorp the Goshen Series Capacitor Bank*, IPUC Case No. IPC-E-09-32, Order No. 31007, 2 (2010) ("Pursuant to Idaho Code § 61-328, the Idaho Public Utilities Commission is charged with the responsibility to review the sale of electric public utility property to ensure that (1) the transaction is consistent with the public interest, (2) the cost of electricity and service rates will not be increased because of the transaction, and (3) the buyer of the electric utility's property has both the intent and the financial ability to operate the property in the public service.").

Given all of the powers vested in the Idaho Commission by its organic statutes—including the power to investigate and fix rates and regulations (I.C. § 61-503), the responsibility to determine the reasonableness of rates (I.C. § 61-502), the responsibility to determine rules and regulations affecting the performance of public utilities (I.C. § 61-507), the responsibility to approve transfers of utility property (I.C. § 61-328), and the responsibility to review and approve the terms and conditions of PURPA contracts—the Commission has organic authority comparable to the authority the commissions of West Virginia, Connecticut, and Wyoming concluded was adequate authority to consider and decide the ownership of RECs.

3. *The Idaho Commission Should Hold that Utilities Own All Environmental Attributes or RECs Associated with QF Energy Sold to the Utilities Under the PURPA Must-Buy Obligation*

As discussed above, states determine who owns RECs and the Commission has jurisdiction to decide ownership of RECs in Idaho. Most utility commission decisions on REC ownership involve circumstances where the state has enacted an RPS program but the renewable energy in question is sold under PURPA contracts executed before the state established its RPS program (or any associated REC program).[10] Because the PURPA contract pre-dates the RPS program, the contract typically is silent regarding ownership of environmental attributes. In the absence of an express contractual provision, state commissions are left to decide who owns the attributes as a

[10] At least nine state commissions have faced these circumstances and all reportedly concluded they utility owns the RECs. *See In the Matter of the Ownership of Renewable Energy Certificates*, 913 A.2d 825, 828 (N.J. Super. 2007) (citing Edward A. Holt, et al., *Who Owns Renewable Energy Certificates? An Exploration of Policy options and Practice*, at xiv (Ernest Orlando Lawrence Berkeley National Laboratory 2006). The most helpful decisions—either because they have been thoroughly appealed or because they contain particularly clear analysis—can be found in the following jurisdictions: **Connecticut**: cases culminating in Connecticut Supreme Court decision *Wheelabrator Lisbon, Inc.*, 931 A.2d 159. **West Virginia**: cases culminating in West Virginia Supreme Court decision *City of New Martinsville*, 2012 W. Va. LEXIS 308. **Pennsylvania**: cases culminating in Pennsylvania court of appeals decision *ARIPPA*, 966 A.2d 1204. **New Jersey**: cases culminating in New Jersey court of appeals decision *In the Matter of the Ownership of Renewable Energy Certificates*, 913 A.2d 825.

matter of state law and policy. The question becomes: Who owns environmental attributes when a utility is required to buy renewable energy under a PURPA contract but there was, or is, no state RPS or REC program in place at the time the contract was executed? This is essentially the same question faced by the Idaho Commission. In response to this question, state commissions have generally held, and state courts have affirmed, that the utility owns the RECs.[11]

In 2004, the Connecticut Department of Public Utility Control ("DPUC") was faced with the question of who owned RECs (referred to as "GIS Certificates") when a utility bought renewable energy under a PURPA contract that had been executed before the state adopted its RPS program. *Petition of the Riley Energy Corp. for Contract Approval*, Conn. PUC Docket No. 91-01-12RE01, 2004 Conn. PUC LEXIS 148 (December 6, 2004). The DPUC held that the GIS Certificates quantify the renewable attributes of the electricity sold by the QF to the utility and that—because the parties and DPUC intended that the PURPA contract necessarily involve the sale of renewable energy—the utility obtained ownership of the GIS Certificates as part of its ownership of the renewable power. *Id.* at *31-32 ("The GIS Certificates, which nominally quantify the renewable energy attributes of the 'electricity' are and were intended by the Department to be sold by Riley [the QF] and purchased by CL&P [the utility].").

[11] *See, e.g., Wheelabrator*, 931 A.2d at 163 ("... we conclude the [state utility commission] reasonably determined that the [renewable energy] certificates were owned by the utility"); *City of New Martinsville*, 2012 W. Va. LEXIS 308 at*33 ("... the decision of the Commission finding that the credits at issue are owned by the Utilities is affirmed."); *ARIPPA*, 966 A.2d at1214 ("... this court accepts the Commission's persuasive interpretation and reasoning in concluding that electric distribution companies own the credits ..."); *In the Matter of the Ownership of RECs*, 913 A.2d at492; *see also* Edward A. Holt, et al., *Who Owns Renewable Energy Certificates? An Exploration of Policy options and Practice*, at xiv (Ernest Orlando Lawrence Berkeley National Laboratory 2006); *but see*, *Petition of Southwestern Pub. Ser. Co. for Declaratory Order Interpreting Commission Rule Implementing Pubic Utility Regulatory Act*, 2005 Tex. PUC LEXIS 6, *11 (March 16, 2005) (Texas Commission determines RECs are owned by QFs where state regulation expressly requires award of RECs to generators of energy).

The DPUC's decision was appealed and upheld by the Superior Court of Connecticut. *Wheelabrator Lisbon, Inc.* 2006 Conn. Super. LEXIS 858. The Superior Court noted: "[The QF's] argument is that GIS Certificates are unrelated to the electricity generated and sold to [the utility]." *Id.* at *17. This is was essentially an argument by the QF that the RECs were "unbundled" before sale of the energy to the utility. The Superior Court further notes with approval:

> The department rejected this argument finding that the GIS Certificates merely quantified the renewable attributes of the renewable fuel generated electricity. Thus, the GIS Certificates can not exist apart from the generated electricity. DPUC found the GIS Certificates inseparable from the renewable energy. . . . The DPUC determined from the evidence that the GIS Certificates were an integral part of renewable energy and that the [PURPA contract] conveyed renewable energy generated by [the QF] to [the utility]. Thus, the GIS Certificates were also conveyed by such agreement.

Id. at *17-18. Effectively, the Connecticut commission found that, in the context of a PURPA contract entered into before the state had any RPS or REC program, the renewable energy and associated environmental attributes remain bundled and the utility compelled to purchase the renewable energy also obtains the associated environmental attributes.

The Superior Court's decision was then appealed to the Supreme Court of Connecticut which also upheld the DPUC's determination that the utility owns the environmental attributes. *Wheelabrator Lisbon, Inc.,* 931 A.2d 159. In upholding the DPUD decision, the Connecticut Supreme Court observed that the very concept of "unbundling" established by the state's RPS program and the state's use of GIS Certificates implies that prior to adoption of a program authorizing "unbundling" the environmental attributes of renewably generated electricity are an inherent attribute of that electricity. As a result, electricity sold by contract executed before the state established its RPS program is electricity that inherently includes any environmental attributes. As the Supreme Court held:

> [T]he term "unbundling" itself implies that the renewable attribute of the energy generated by renewable energy sources is an inherent attribute of the energy ... It was reasonable, therefore, for the department to conclude that the word "electricity," as used in ... the 1991 agreement [the PURPA contract], meant renewable energy. In other words, the terms "electricity" necessarily includes the renewable attribute that later was "unbundled" from the energy [per the states subsequent RPS program] and represented by the [GIS] certificates. Accordingly, we conclude that the department reasonably determined that the certificates were owned by the utility.

Id. at 176.

The New Jersey Board of Public Utilities ("BPU") has similarly held that where a utility is compelled to purchase renewably generated energy under a PURPA contract executed before New Jersey established a RPS program, the utility owns the environmental attributes. *In the Matter of the Ownership of RECs*, BPU Docket No. E004080879. More specifically, the BPU held:

> . . . as a matter of law and policy . . . that with respect to existing QF . . . contracts, the sale of power to the [utilities] in the first instance, and the [BPU's] approval of the sale and the terms and conditions associated therewith, were inextricably linked to the renewable attribute thereof and that special consideration was given by the [BPU] to the renewable projects because of the renewable nature of the power being sold. Therefore, the [BPU] FINDS that these attributes belong to the purchasing [utilities] for the duration of those contracts . . .

Id. at 18. The New Jersey court of appeals upheld the BPU's determination that utilities own the RECs from power purchased under PURPA contracts that pre-date the state's RPS program. *In the Matter of the Ownership of RECs*, 913 A.2d 825 (N.J. Super. 2007). The court of appeals noted that assignment of the RECs to the QFs would have meant that retail customers would pay more for electricity and the court concluded that "this result would be unfair to retail customers, who have already paid for [the QF's renewably-generated] electricity, and it is entirely inconsistent with the governing state legislation." *Id.* at 830.

The Maine utility commission has also considered REC ownership in the context of PURPA sales. *See, Investigation of GIS Certificates Associated with Qualifying Facility Agreement*, Me. PUC Docket No. 2002-494, 2003 Me. PUC LEXIS 74, *7 (February 14, 2003) ("The Commission has initiated an Investigation and has tentatively concluded that the utilities have the right to the GIS certificates associated with QF contracts and that the certificates should be transferred to the entitlement purchaser."). The Maine commission was of the opinion that environmental attributes remain bundled when renewable power is sold under a PURPA contract. *See, Petition for Declaratory Order Regarding Ownership of Alternative Energy Credits*, Pa. PUC P-00052149, 2006 Pa. PUC LEXIS 110, *60-61 (July 5, 2006) (discussing the Maine PUC's position that environmental attributes remain bundled with power sold under PURPA and therefore are owned by the purchasing utility). However, the Maine commission suspended its investigation of the question pending the outcome of the *American Re-Fuel* proceeding before FERC. The Maine commission then subsequently terminated its investigation without resolving the question of REC ownership. *Investigation of GIS Certificates*

Associated with Qualifying Facility Agreement, Me. PUC Docket No. 2002-506, 2007 Me. PUC LEXIS 152 (June 11, 2007).

The Pennsylvania PUC has also ruled on ownership of RECs in the context of a PURPA contract executed before there was any state RPS program. *Petition for Declaratory Order Regarding Ownership of Alternative Energy Credits*, 2006 Pa. PUC LEXIS 110, *60-61. The Pennsylvania Commission held that "the ownership of the alternative energy credits generated within the long-term power purchase agreements entered into pursuant to PURPA prior to the passage of the Alternative Energy Portfolio Standards Act, 73 P.S. §§1648.1 *et seq.*, which do not anticipate or mention the alternative energy credits, belong to the electric distribution companies [the purchasing utilities]." *Id.* at *92. The Pennsylvania Commission reasoned that to rule otherwise would create a perverse result where the utility and its customers would not get credit for purchasing renewable generation when that is in fact what they are doing under the PURPA contract. *Id.* at *35. Effectively, the Pennsylvania Commission found that the environmental attributes and energy remain bundled in a PURPA sale that was contracted for before the state adopted an RPS program. The decision was challenged but upheld by the Pennsylvania court of appeals. *ARIPPA v. Penn. PUC*, 966 A.2d 1204 (Pa. Commw. 2009). The court held:

> the purpose of [Alternative Energy Portfolio Standards Act (AEPS)] is to encourage the creation and use of energy from alternative sources, and the fact that the credits are a tradable commodity is a secondary effect of the statutory scheme to effectuate that goal. Where, as here, the [utility] has already purchased energy from an alternative energy supplier (albeit under a pre-2005 agreement that made no provision for alternative energy credits), the underlying purpose of AEPS has been satisfied. Nonetheless, if the credits attributable to that power belong to the [QF]

> generating company, the [utility] will have to purchase credits separately and pass that additional charge along to the consuming public. Thus, the Commission concluded that the public interest favored awarding ownership rights in the credits to the [utility]. Moreover, the contracts themselves are entirely silent on the issue of these rights, and any attempt to determine the parties' intent or how they might have structured the contract if they had anticipated the future creation of saleable credits is speculative at best. Thus, as there is no controlling statutory language in the applicable version of AEPS, no controlling precedent, and no guiding language in the contracts themselves, this court accepts the Commission's persuasive interpretation and reasoning in concluding that [utilities] own the credits under the circumstances presented here.

Id. at 1214.

In each of the decisions discussed above, a state utility commission considered who owned the environmental attributes associated with power sold under PURPA contracts executed before adoption of an RPS statute. In effect, these decisions analyze who should own environmental attributes when a PURPA contract is executed in the absence of a state RPS statute. That is the very question currently before the Idaho Commission. The reasoning in the above decisions is therefore instructive.

In each case, the state utility commission effectively decided that, in the absence of a state RPS, the QF energy sold under a PURPA contract transfers a bundled product. The utility therefore obtains ownership of both the energy and the bundled environmental attributes. When a QF compels a utility to purchase renewably-generated energy under a PURPA contract, and it does so in a state like Idaho that has no RPS statute, then the QF has no statutory or other right or basis by which to "unbundle" environmental attributes from the renewably-generated energy. The state involved—in this case Idaho—determines initial ownership of RECs and when and how

RECs can be traded or sold. *American Ref-Fuel I*, 105 FERC ¶ 61,004, P23. There is no right or ability to "unbundle" energy and environmental attributes and to thereby create RECs unless and until the state has established such a right. Simply put, in the absence of an Idaho RPS statute, there is no reason to conclude that a QF selling to an Idaho utility has any right or ability to unbundle energy and environmental attributes.

It appears that the Wyoming Public Service Commission has adopted this approach. By order issued November 4, 2011, the Wyoming PSC held that RECs associated with QF sales in Wyoming are owned by the utility. *In the Matter of the Application of Rocky Mountain Power to Implement a Permanent Avoided Cost Methodology for Customers that do not Qualify for Tariff Schedule* 37, Wy. Public Service Commission, Docket No. 20000-388-EA-11, Record No. 12750, at PP 63-64 2011 Wyo. PUC LEXIS 441(2011). The critical holdings on RECs are made in paragraphs 63 and 64 of the order, which state:

> 63. [Interwest Energy Alliance (IEA)] advocated the QF should retain the RECs until such time as the wind proxy is included in the QF pricing determination or the REC value is included in the pricing determination (if the utility retains the RECs). The Commission finds IEA has failed to support its proposed treatment of RECs. The Commission finds the testimony of [Rocky Mountain Power (RMP)] witness Clements more persuasive on this issue. In his rebuttal testimony, Clements gives two reasons why RECs should be retained by the utility. (RMP Exhibit 4, pp. 2-3.) The Commission finds his second argument, i.e., "Wyoming customers should not have to pay something extra for—or be deprived of the right to truthfully claim—something that is actually taking place, which is PacifiCorp's purchase of energy from a particular QF" to be the more persuasive. (RMP Exhibit 4, p. 3.) Consistent with the current treatment of RECs, the Commission finds RMP should continue to retain the RECs since they represent tangible value for the ratepayer, and they should not be routinely severed from the underlying green power generated. The Commission has in

> the past made it clear that REC revenues are a key component used to mitigate, to an extent, the effects on customers of the ongoing series of rate increases filed by RMP. The Commission is not inclined to approve the transfer of RECs to other entities and reiterates its position that RECs should stay with the utility.
>
> 64. IEA's assertion that wind development will not occur if RECs are not allowed to be retained by the QF is not supported by the facts, as the evidence shows that wind development by substantial QF entities has occurred in the state. Further, IEA's assertion that REC retention by the QF serves as a tool in encouraging economic development is not a viable argument because the Commission is not an economic development agency. Further, RMP is not an economic development agency but rather a business entity engaged in securing green energy and reasonable prices and under reasonable conditions on behalf of its consumers and itself.

The Wyoming PSC's holdings are consistent with a theory that the environmental attributes associated with QF power remain bundled with the power purchased by the utility. The Wyoming PSC stated that the utility "should continue to retain the RECs ... and they should not be routinely severed from the underlying green power generated. ... The Commission is not inclined to approve the transfer of RECs to other entities and reiterates its position that RECs should stay with the utility." *Id.,* at 63. These statements are remarkably consistent with the theory that the environmental attributes or RECs remain bundled with the energy. Perhaps this is not surprising because Wyoming, like Idaho, has no RPS statute.

In the absence of an RPS statute, it would seem to be most consistent with state law to hold that environmental attributes and energy remain bundled. Like the Wyoming PSC, the Idaho Commission can best serve the public interest by concluding that in Idaho, and in the absence of a legislatively mandated RPS program, the environmental attributes associated with QF output remain bundled with the power and that the utility therefore owns the environmental attributes as a consequence of purchasing the bundled power, all of which ultimately flows back as a benefit to Idaho Power's customers.

As the state utility commissions in Wyoming, Pennsylvania, New Jersey, Connecticut, and West Virginia have all found, there are sound public interest reasons to conclude that, in the absence of an RPS or other state statutory requirement to the contrary, QF output purchased in Idaho is a bundled product and includes both renewable energy and environmental attributes.

4. Awarding RECs to the Utility Does Not Make a Constitutional Taking or Conflict with American Ref-Fuel

As discussed above, it is in the public interest for the Commission to conclude that all energy sold in Idaho under the PURPA must-buy obligation is bundled energy and the utility buyer therefore owns the energy and any associated environmental attributes. As a result, any RECs that may arise from such environmental attributes are owned in the first instance by the utility. For the reasons discussed below, this outcome does not represent an unconstitutional taking nor does this outcome conflict with FERC's holding in *American Ref-Fuel.*

In many of the cases discussed above—where a state utility commission determined that RECs or environmental attributes belonged to the utility—the QF argued that such an outcome represented in an unconstitutional taking without compensation in violation of the state and federal constitutions. The courts have consistently rejected this argument. Idaho Power is not aware of a single case where the state law decision to assign initial ownership of a REC to a utility was found to constitute an unconstitutional taking.

In *Wheelabrator Lisbon Inc.*, 931 A.2d 159, the Supreme Court of Connecticut rejected the takings argument. It held:

> The trial court concluded in the present case that the transfer of the certificates to the utility did not constitute an unconstitutional taking of property from the plaintiff because the certificates were not the plaintiff's property. We have concluded that the trial court correctly determined that it was within the jurisdiction of the department to determine the ownership of the certificates and that the department reasonably concluded that the utility owned them. Accordingly, we agree with the trial court that the department's decision could not constitute an unconstitutional taking under the state constitution because no property owned by the plaintiff had been taken.

Id. at 177. In reference to the same decision by the Connecticut PUC, the United States District Court for the District of Connecticut held that there was no violation of the federal constitution:

> The generators claim that the [Connecticut] PUC's decisions, ordering them to transfer the [RECs] to [the utility] violate the . . . *Takings Clause*. . . . The RECs . . . are creations of state legislation and regulation, and the [Connecticut] PUC has determined that [the utility] is the owner of the [RECs] associated with the renewable energy it purchases from [the QFs] pursuant to the parties' [power purchase agreements]. Accordingly, the generators have not been deprived of a property interest because NEPOOL's initial assignment to them did not confer ownership of RECs. . . .

Wheelabrator Lisbon Inc., v. Connecticut PUC, 526 F. Supp. 2d 295, 306-07 (Conn. Dist. 2006).

The Supreme Court of West Virginia has also rejected the takings argument. In *City of New Martinsville v. Pub. Ser. Comm. of West Virginia*, 2012 W. Va. LEXIS 308 at *27 n.13 (2012), it held:

> MEA also argues that Commission's decision to award the credits to the Utilities results in the taking of private property without just compensation to the owners, i.e., the Generators, in violation of the federal and state constitutions. Again, we find no merit to this argument because the Commission determined that the credits were owned by the Utilities in the first instance. The Commission's decision could not constitute an unconstitutional taking because no property owned by the Generators was taken.

As another example, the Colorado PUC has also rejected the takings argument. *In the matter of the proposed rules implementing renewable energy standards 4 CCR 723-3*, Co. PUC Docket No. 05R-112E, Decision No. C06-0091, at P 45, 2006 Colo. PUC LEXIS 67 at *31 (2006) (After deciding RECs are owned by the utility under PURPA contracts that pre-date the state's REC legislation, the Colorado PUC rejected the takings argument holding the "QFs have no vested property interest in the RECs ... we find that no taking could have occurred.").

If the Idaho Commission decides that environmental attributes remain bundled as part of the sale of energy under an Idaho PURPA contract, and if the Commission therefore concludes that the utility owns any RECs in the first instance—the Commission can also reject any takings argument on the grounds that the QF never owned the RECs.

For the same reason, it is not necessary to include, or create, any upward adjustment to the avoided cost price paid for QF power in an attempt to compensate QFs for the value of a REC. If the Commission determines that utilities own the RECs in the first instance, there is no need to compensate QFs because there has been no transfer of REC ownership. In consequence, the Commission should reject staff's suggestion that avoided cost rates should be adjusted to account for the transfer of RECs. Sterling, Direct, p. 46-47.

Further, the approach recommended by Idaho Power does not conflict with FERC's holding in *American Ref-Fuel.* As discussed in section A above, *American Ref-Fuel* as interpreted on rehearing and by the Second Circuit in *Wheelabrator*, 531 F.3d 183, announces the following principles: (1) ownership of RECs is decided by state law, not PURPA; (2) a PURPA sale does not inherently involve the transfer of RECs; and (3) avoided cost rates compensate for energy and capacity only, they do not compensate for the transfer of RECs.

Under these principles, it would conflict with PURPA for a state commission to hold that QFs are the initial owners of RECS but that a PURPA sale automatically transfers ownership of the REC to the utility and the payment of avoided cost provides the QF with compensation for the change in REC ownership. The *American Ref-Fuel* decision gives states the latitude to decide that either a utility or a QF owns RECs as an initial matter. But it does not give states the latitude to hold that unbundled RECs, owned in the first instance by the QF, are transferred to the utility as a necessary consequence of a PURPA sale. *See American Ref-Fuel*, 107 FERC 61,016 at n.1 ("... a PURPA contract [does] not inherently convey any RECs ...."). However, as both FERC and the Second Circuit have recognized, a REC may change ownership as part of a PURPA sale if transfer is by express agreement of the parties or by application or operation of some state law requirement. *Id.*; *Wheelabrator*, 531 F.3d at 189. The point is that a state cannot deem a transfer of RECs to have occurred as an inherent consequence of the PURPA-mandated sale of QF power.

It would also run afoul of *American Ref-Fuel* for a state commission to declare that the avoided cost rates alone provide compensation or consideration for the transfer of RECs from the QF to the utility.[12] However, under the approach advocated by Idaho Power, the Commission need not find that avoided cost rates provide adequate compensation for RECs because no RECs are transferred. Rather, the Commission can and should conclude that the environmental attributes remain bundled as an inherent part of the energy and capacity sold under the PURPA contract and that the utilities are the owners of any RECs in the first instance.

5. ***The Commission Should Use Its Inherent Authority to Recognize That, in the Absence of a State RPS and REC Program, Ownership of RECs Associated with Idaho QFs Belong to the Utilities***

This Commission has, until now, refrained from determining or declaring the rights of the utility to RECs from Idaho QFs. Unless the Commission exercises its jurisdiction to decide ownership of RECs soon, Idaho QFs may cause serious harm to ratepayers by employing a "REC stripping scheme" recently reviewed by FERC to unilaterally claim ownership of RECs in the face of inaction by the Commission and the Idaho Legislature. In *Idaho Wind Partners*, FERC found that a QF could sell and

[12] FERC has clearly stated "avoided cost rates are not intended to compensate the QF for more than capacity and energy." *American Ref-Fuel*, 107 FERC 61,016 at P15. However, the soundness of this conclusion has been questioned. *See Wheelabrator*, 931 A.2d at n. 25 (the Connecticut Supreme Court notes that FERC was split on the question of whether avoided costs can be found to compensate for RECs, that the decision has been criticized by commentators, that the court in New Jersey declined to follow it, and that the decision appears to be inconsistent with the United States Supreme Court's determination in *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402, 406 (1983), that the avoided cost scheme was intended to provide an incentive to develop renewable energy sources). Furthermore, FERC's holding in *American Ref-Fuel* is presently "of no legal moment" and represents nothing more than an announcement of the position FERC may take in a future enforcement action. *Xcel Energy Services, Inc. v. FERC*, 407 F.3d 1242, 1244 (D.C. Cir. 2005).

repurchase QF output before the point of delivery, and resell it to the utility, stripped of RECs, consistent with PURPA. *See, Idaho Wind Partners 1, LLC*, 134 FERC ¶ 61,217 (March 17, 2011), *order granting clarification and dismissing rehearing*, 135 FERC ¶ 61,154 (May 19, 2011), *rehearing dismissed*, 136 FERC 61,174 (September 15, 2011)[13] This transaction makes clear that, even though Idaho does not have a REC program, there is some environmental attribute from QF output that has commercial value, and QFs are likely to use this transaction to deprive utilities of that value absent action by the state or Commission.

The specter of QFs stripping environmental attributes so that they may be sold to third parties notwithstanding unresolved issues of ownership threatens to deprive the customers of significant value or, at the least, cause protracted litigation to unwind such transactions. This threat presents REC ownership in a different context than in past Commission proceedings on RECs. Whereas until recently, QFs and utilities resolved ownership of RECs contractually, the *Idaho Wind Partners* decision gives QFs a mechanism to unilaterally deprive utility customers of any benefits associated with RECs.

QF control over RECs runs counter to numerous other states' findings that pre-RPS RECs originate with the utility (See, *supra,* n. 10) and runs counter to the Wyoming Public Service Commission's finding that RECs remain with Wyoming utilities. These precedents favoring utility ownership of environmental attributes from QFs where the

[13] Idaho Wind Powers petitioned for a declaratory order asking FERC whether it would violate PURPA or jeopardize QF states if a first QF sells its renewable power to a second QF and then instantaneously re-buys its power from the second QF without the RECs (which remain with the second QF) before compelling a public utility to purchase the unbundled (and "REC-less") power pursuant to the PURPA must-buy obligation; FERC has stated that such a transaction does not violate PURPA or jeopardize QF status. *Idaho Wind Partners 1, LLC.* 134 FERC ¶ 61,217, P 19-21.

state does not have an RPS or a REC program are not controlling; however they are evidence of the strength of the utility's claim of REC ownership. QF control of environmental attributes from Idaho QFs also runs counter to the recommendation of the Idaho Staff. Commission staff takes the position that the utility should own the environmental attributes from an Idaho QF because such ownership is in the public interest. Sterling, Direct, p. 42. Although Idaho utilities are not subject to an RPS at present, it might become subject to a federal or state RPS in the future. In that event, if the utility does not retain the environmental attributes from QF contracts, it might need to purchase RECs to comply with future RPS standards. Such an outcome would result in the utility's customer paying more for power.

The "REC stripping scheme" proposed by QFs in *Idaho Wind Partners*, 134 FERC ¶ 61,217, P 1, would be ineffectual if environmental attributes remain bundled until a QF sells to a utility under PURPA. Because environmental attributes and energy must remain bundled, the "inside the fence" transactions proposed by the QFs in *Idaho Wind Partners* cannot unbundle RECs and strip them prior to sale of energy to utilities.

Idaho Power urges the Commission to look at its authority to regulate environmental attributes associated with Idaho QFs in light of the threat of harm posed by schemes designed to strip RECs and deprive utility customers of those benefits. The fact that the rights to such attributes are being bought and sold notwithstanding the fact that Idaho does not have an RPS or REC program suggests that they may be property subject to the Commission's jurisdiction under Idaho Code § 61-328 (see *supra,* Section II.E.2). If environmental attributes are property of the utility, then they are subject to Commission jurisdiction and regulation.

The consensus among other states that environmental attributes from QF power flow to the utility prior to the creation of a state RPS or REC program suggests that the utilities own such environmental attributes in Idaho as well. Where actions are occurring that threaten to deprive Idaho's electric utilities of valuable property that they will need to comply with a future state or federal RPS, the Commission has a strong interest in protecting the public interest. The fact that ownership of RECs from Idaho QFs is a matter squarely within the Commission's administrative expertise and that *Idaho Wind Partners* threatens to moot the issue of ownership unless the Commission suggest that this issue is neither theoretical nor beyond the Commission's jurisdiction.

6. In the alternative, the Commission Should Authorize the Utilities to Include a "Reservation of Rights" Provision in Each QF Power Purchase Agreement Clarifying that Ownership of RECs is Currently Undetermined But Will Follow Any Determinations Ultimately Made by Idaho Statute or Regulation

If the Commission declines to decide ownership of RECs, Idaho Power urges the Commission to confirm, as it did in Grand View Solar Order No. 32580, that ownership of RECs is a question of state law, to confirm that the State of Idaho has not yet answered the question, and to authorize the utilities to include a "reservation of rights" provision in each QF power purchase agreement. If the QF and the utility can agree on an allocation of RECs, then a "reservation of rights" provision will be unnecessary and the power purchase agreement can simply state the Parties agreement on ownership of RECs. Otherwise, in the interest of avoiding further dispute, the utility should have the right to insert a "reservation of rights" provision. The reservation of rights provision would state the following points:

> (1) The parties have not agreed to a contractual allocation of any RECs;

> (2) Ownership of any RECs associated with the energy and capacity sold under the power purchase agreement is a question of state law;
>
> (3) The State of Idaho has not yet established whether the utility or the QF owns such RECs in the first instance; and
>
> (4) The parties to the PPA acknowledge that ownership of any RECs associated with the energy and capacity sold under the PPA will be as ultimately determined by future Idaho statute, Idaho Public Utilities Commission regulation, or other determination of Idaho law made by the Idaho Legislature, the Idaho courts, by the Idaho Public Utilities Commission, or by any other entity, state or federal, with jurisdiction and authority to determine the issue.

A reservation of rights provision of the type describes above is in the public interest. It will put the parties in future PURPA contracts on notice that ownership of RECs is currently unsettled in Idaho. It will clearly reserve both party's rights regarding ownership of RECs. And it will avoid the need for litigation of the type currently pending before the Commission in *Grand View PV Solar Two, LLC, v. Idaho Power Co.*, IPUC Docket No. IPC-E-11-15, a complaint proceeding brought by a QF in an attempt to compel Idaho Power to agree that it is not the owner of the RECs associated with the energy and capacity to be sold under a proposed QF power purchase agreement.

The Commission has the authority to authorize a reservation of rights provision like that proposed by Idaho Power. *See, Idaho Power Co. v. Cogeneration, Inc.*, 129 Idaho 46, 49 (1996) (Idaho Commission has the authority to approve the terms and conditions of PURPA contracts); *Afton Energy v. Idaho Power Co.*, 107 Idaho 781, 789 (1984) (affirming Commission jurisdiction over issues related to QF contracts and noting that "[c]ontracts entered into by public utilities with [QFs] or decisions not to contract with [QFs] have a very real effect on the rates paid by consumers both at present and in the future."), *modified on reh'g* 107 Idaho 781, 793 (1984); *Grand View PV Solar Two, LLC v. Idaho Power Company*, IPUC Docket No. IPC-E-11-15, Order No. 32580, at 7 (2012) (discussing Commission's jurisdiction over QF contracts).

The proposed reservation of rights provision does not compel any concession of rights from the QF or the utility. It merely acknowledges the current undecided state of the law in Idaho and acknowledges what is already true—that ownership of RECs will be determined by extant Idaho law. *Fidelity Trust Co. v. State et al.*, 72 Idaho 137, 149 (1951) ("... it is axiomatic that extant law is written into and made a part of every written contract.").

While the precise language of the reservation rights provision could take many forms so long as it establishes the four key points listed above, Idaho Power proposes the following provision for consideration and approval by the Commission:

> <u>Reservation of Rights Regarding Ownership of RECs</u>
>
> The Parties make no contractual assignment or transfer regarding the ownership of Green Tags or Renewable Energy Certificates (RECs) associated with the energy and capacity generated by Seller's Facility and sold to Idaho Power under this Agreement. The Parties further acknowledge and agree that Idaho law controls the question of which Party owns such Green Tags or RECs but that the State of Idaho has not yet decided the question. As such, both Parties hereby expressly reserve any and all rights that they have under current or future Idaho law regarding ownership of such Green Tags or RECs. The Parties acknowledge that ownership of such Green Tags or RECs will be as determined by future Idaho statute, Idaho Public Utilities Commission regulation, or other applicable determination of Idaho law made by the Idaho Legislature, the Idaho courts, the Idaho Public Utilities Commission, or by any other entity, state or federal, with jurisdiction and authority to determine the issue.

III. CONCLUSION

For the reasons above, Idaho Power respectfully requests that the Commission grant the relief requested herein.

DATED this 20th day of July 2012.

DONOVAN E. WALKER

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 20th day of July 2012 I served a true and correct copy of the LEGAL BRIEF OF IDAHO POWER COMPANY upon the following named parties by the method indicated below, and addressed to the following:

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Christa Bearry

Christa Bearry, Legal Assistant

NON-PARTY CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 20th day of July 2012 I served a true and correct copy of the LEGAL BRIEF OF IDAHO POWER COMPANY upon the following individuals who are not named parties in this proceeding by the method indicated below, and addressed to the following:

Big Wood Canal Company and American Falls Reservoir District No. 2 C. Thomas Arkoosh CAPITOL LAW GROUP, PLLC 205 North 10th Street, 4th Floor P.O. Box 2598 Boise, Idaho 83701-2598	____ Hand Delivered _X_ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email tarkoosh@capitollawgroup.com
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Michael J. Uda UDA LAW FIRM, P.C. 7 West 6th Avenue, Suite 4E Helena, Montana 59601	____ Hand Delivered _X_ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email muda@mthelena.com

Christa Bearry

Christa Bearry, Legal Assistant

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

EXHIBIT NO. 12

REQUEST NO. 6: If Idaho Power's proposed Schedule 74 were to be approved by the Commission and QFs were curtailed during certain low load conditions, would the avoided cost rates computed based on Aurora analysis be impacted? Has Idaho Power conducted any Aurora analysis to compute avoided cost rates under an assumption that QFs could be curtailed under certain low load conditions?

RESPONSE TO REQUEST NO. 6: Avoided cost rates computed by AURORA are set for the duration of the contract based upon the QF's estimated hourly generation profile for a period of one year, and this computation is not impacted by possible curtailment. However, if Idaho Power must pay for curtailment, it must also be able to recover such payments. If Idaho Power may curtail without payment, no adjustment to avoided costs through the integration charge is necessary.

In its updated wind integration study, the Company has been careful to not include any costs associated with curtailment in the wind integration cost analysis. The AURORA model used by Idaho Power to determine the avoided cost of energy is not capable of modeling wind curtailment and therefore curtailment is not valued in the pricing proposed by Idaho Power. Because a certain amount of curtailment is anticipated in the modeling performed as part of the wind integration study, Idaho Power does not believe it would be appropriate to account for curtailment in the avoided cost pricing model.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

EXHIBIT NO. 13

REQUEST FOR PRODUCTION NO. 19: Reference the Direct Testimony of Tessia Park, p. 20, stating, "Pursuant to FERC licenses Idaho Power has for its run-of-river hydro electric projects, the Company is obligated to take whatever generation flows through them; it does not have the ability to decrease or increase the generation."

(a) Please identify each of the run-of-river hydro plants and provide the capacity of each.

(b) Please provide the FERC license for each project (in electronic format if available).

(c) Please identify the provision (page number, section number, as applicable) in each FERC license that Idaho Power relies on to determine it does not have the ability to decrease or increase the generation.

(d) For each plant, please explain whether the plant has the operational capability to spill water without generating electricity, and any restrictions on Idaho Power's ability to do so.

RESPONSE REQUEST FOR PRODUCTION NO. 19:

(a) Following are the run-of-river hydro plants and their capacity:

Milner – 59.45 MW
Twin Falls – 52.74 MW
Shoshone Falls – 12.5 MW
Upper Salmon Falls A – 18 MW
Upper Salmon Falls B – 16.5 MW
Lower Salmon Falls – 60 MW
Upper Malad – 8.27 MW
Lower Malad – 13.5 MW
Bliss – 75 MW
Swan Falls – 25 MW

(b) Electronic versions of the licenses identified above are provided in the non-confidential CD.

(c) Milner. A complete reading of the Milner license shows that the Milner project is designed to generate with flows that are not used for irrigation as they pass through the project (run-of-river).

Twin Falls. A complete reading of the Twin Falls license shows that the Twin Falls project is designed to generate with flows as they pass through the project (run-of-river).

Shoshone Falls. A complete reading of the Shoshone Falls license shows that the Shoshone Falls project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Upper Salmon Falls A. A complete reading of the Upper Salmon Falls license shows that the Upper Salmon Falls project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Upper Salmon Falls B. A complete reading of the Upper Salmon Falls license shows that the Upper Salmon Falls project is designed to generate with flows as they pass through the project (run of river). See Article 401.

Lower Salmon Falls. A complete reading of the Lower Salmon Falls license shows that the Lower Salmon Falls project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Upper Malad. A complete reading of the Malad license shows that the Malad project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Lower Malad. A complete reading of the Malad license shows that the Malad project is designed to generate with flows as they pass through the project (run of river). See Article 401.

Bliss. A complete reading of the Bliss license shows that the Bliss project is designed to generate with flows as they pass through the project (run-of-river). See Article 401.

Swan Falls. A complete reading of the Swan Falls license shows that the Swan Falls project is designed to generate with flows as they pass through the project (run-of-river).

In addition, the non-confidential CD contains a copy of a Settlement Agreement between Idaho Power and the U.S. Fish and Wildlife Service which contains certain environmental provisions that place constraints around how the Company operates the Mid-Snake hydro projects (e.g.), Shoshone Falls, Bliss, Upper Salmon, and Lower Salmon).

At run-of-river projects, generation increases as flow increases and generation decreases as flow decreases.

(d) Each licensed facility has the physical capability to spill water without generating electricity. The proposed operations in the applications for FERC licenses and state water quality certifications did not include spill except when flows exceeded plant capacity or when generators tripped off-line in emergency situations. To the contrary, operations may require an amendment to the FERC licenses and/or state water quality certifications.

The response to this Request was prepared by Lewis Wardle, Senior Biologist, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

EXHIBIT NO. 14

REQUEST FOR PRODUCTION NO. 20: Reference the Direct Testimony of Tessia Park, p. 23, stating, "the Company must maintain constant flows below Hells Canyon dam for environmental compliance, thus limiting the ability to curtail generation out of the Hells Canyon Complex to no less than approximately 350 MW."

(a) Please identify the individual plants/dams at the Hells Canyon Complex and the MW capacity of each.

(b) Please explain the environmental compliance requirement for each that limits the ability to curtail generation and provide the minimum generation of each individual project. Please identify the government agency imposing the compliance requirement.

(c) For each plant, please explain whether the plant has the operational capability to spill water without generating electricity. Please explain why generation cannot be curtailed to 0 MW by spilling, or to any cumulative output below 350 MW for the Complex.

RESPONSE TO REQUEST FOR PRODUCTION NO. 20:

(a) The Hells Canyon Complex consists of three projects: Brownlee, Oxbow, and Hells Canyon. The nameplate MW ratings for the aforementioned projects are as follows: Brownlee-585.40, Oxbow-190.00, and Hells Canyon-391.50

(b) FERC:

Brownlee, Oxbow, Hells Canyon

- Minimum reservoir level

Hells Canyon Dam

- Minimum flow 13,000 cubic feet per second ("cfs") at Lime Point 95 percent of the time (flows less than 13,000 cfs must be negotiated with Corps of Engineers)

- Maximum ramp rate 1 ft. / hour

- Minimum instantaneous flow 5,000 cfs

Corps of Engineer ("COE"):

Hells Canyon Dam – Requested 13,000 cfs variance

- Minimum instantaneous flow 8,500 cfs (measured at Snake River at Hells Canyon) when previous 3-day moving average Brownlee Reservoir inflow is at or above 8,500 cfs.

- Minimum instantaneous flow 11,500 cfs (measured at Snake River below McDuff Rapids) unless it would require drafting Brownlee Reservoir.

- When the previous 3-day moving average for Brownlee Reservoir inflow is less than 8,500 cfs, the instantaneous minimum Hells Canyon flow shall not fall below the previous 3-day moving average for Brownlee Reservoir inflow.

National Ocean Atmospheric Administration ("NOAA") – National Marine Fishery Services: (Endangered Species ACT)

- Provide stable Hells Canyon outflow for salmon spawning and establish minimum flow level for spring emergence.

- Provide minimum flow level for spring emergence.

- Perform entrapment surveys for spring emergence salmon to mitigate 4" ramp rate.

Environmental Protection Agency ("EPA") – State Department of Environmental Quality:

- Maintain total dissolved gases ("TDG") below Hells Canyon Dam below 110 Parts Per Million ("PPM")

United States Fish and Wildlife Service:

- Maintain TDG below 110 PPM to protect Endangered Species Bull Trout.

(c) Power plants in the Hells Canyon project are not able to decrease generation to 0 and spill water without generating electricity for the following reasons, as per regulatory standard requirements:

North American Electric Reliability Corporation ("NERC") – Western Electric Coordinating Council ("WECC"):

- NERC Standard BAL-002-1 Disturbance Control Standard ("DCS") – utilize contingency reserve to balance resources and demand and return interconnection frequency within defined limits following a reportable disturbance.

- WECC Standard BAL-002-WECC-1 Contingency Reserve – provide reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies.

- NERC Standard BAL-005-0.2b Automatic Generation Control ("AGC") – provide necessary AGC to calculate Area Control Error ("ACE") and to routinely deploy the Regulating Reserve.

- WECC Standard BAL-STD-002-0 Operating Reserve – provide adequate generating capacity to be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to supply requirements for load variations, replace generating capacity and energy lost due to forced outages of generation or transmission equipment, meet on-demand obligations, and replace energy lost due to curtailment of interruptible imports.

FERC:

- Maintain generation MW levels for undesignated sales.

Hells Canyon Dam TDG will elevate over 110 PPM for spill above 3000 cfs.

The response to this Request was prepared by Tessia Park, Director Load Serving Operations, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

EXHIBIT NO. 15

REQUEST FOR PRODUCTION NO. 21: Reference the Direct Testimony of Tessia Park, p. 1, stating dispatch costs for the Company's coal units are approximately \$30/MWh and for Langley Gulch are \$22/MWh.

(a) Please explain why the Company would not take its coal plants offline and instead run Langley Gulch during times when it expects to have light loading periods.

(b) For Langley Gulch, the run-of-river hydro projects, and the Hells Canyon Complex, please provide the minimum and maximum output for each that Idaho Power could reasonably expect to obtain during periods of the year that Idaho Power expects to experience light loading events. Please explain the basis for the estimates for each category.

RESPONSE TO REQUEST FOR PRODUCTION NO. 21:

(a) Coal plants cannot be shutdown and restarted on a daily basis and, consequently, they can only be turned down to minimum generating levels during light load periods in order to have their capacity available for the next days' heavy load period.

(b) When on-line, Langley Gulch will typically be operated during light loading events between its minimum and maximum generating levels. It is expected that Langley Gulch will be dispatched somewhere between its minimum and maximum levels depending primarily on system load, actual wind generation, and plant economics. The minimum and maximum levels vary seasonally, but are reasonably expected to be about 160 MW and 300 MW, respectively.

The minimum and maximum output for the run-of-river hydro projects during light loading events is dependent on water conditions in the Snake River Basin as no significant reservoir storage is available at any of Idaho Power's projects. The water conditions are very predictable with respect to short-term planning; however, a longer-term basis review of Snake River Basin streamflow records indicates pronounced season-to-season and year-to-year variability. Therefore, expected minimum and maximum output levels depend on the type of water year. For capacity planning purposes, under median water, Idaho Power expects to get 285 MW from the run-of-river plants (see 2011 IRP, page 117).

For light loading events occurring during the nearly eight month period from mid-October through May, the minimum output for the Hells Canyon Complex is driven by Idaho Power's efforts to maintain flow levels suitable for Snake River fall Chinook salmon spawning, rearing, and emergence. Idaho Power manages its operations to provide stable flows during the approximately two month spawning period (mid-October to mid-December) and, after spawning, maintains the Hells Canyon Complex outflows at or above the stable spawning flow level through rearing and emergence (mid-December through May). The spawning flow level varies from year-to-year depending on water supply in the Snake River Basin, but, in the past, has ranged from about 8,500 cfs to 14,000 cfs. While minimum output can vary from hour-to-hour depending on water management for the three dam complex, it is reasonable to estimate minimum output of about 300 MW during years when spawning flows of 8,500 cfs are provided, and about 550 MW during years when spawning flows of 14,000 cfs are provided.

Outside of the mid-October through May period, Idaho Power maintains minimum Hells Canyon Complex outflows in compliance with downstream navigation requirements. These requirements depend on several factors, including inflow to

Brownlee Reservoir and Salmon River discharge, but generally Idaho Power maintains Hells Canyon Complex outflows of 6,500 cfs or higher during this period (June to mid-October). High Brownlee inflow conditions, particularly during the early summer, may necessitate Hells Canyon Complex outflows substantially greater than 6,500 cfs. Minimum output during these high flow periods is variable, and typically quite high. During periods when Hells Canyon Complex outflows can be reduced to levels of approximately 6,500 cfs, it is reasonable to estimate minimum output levels of about 250 MW.

With respect to maximum output, Idaho Power manages the Hells Canyon Complex such that maximum output during light loading periods is typically only nominally higher than the minimum output obtained. Capacity during these periods is not needed, and the flexible generators of the Hells Canyon Complex can vary their output accordingly.

The response to this Request was prepared by M. Mark Stokes, Power Supply Planning Manager, Idaho Power Company, in consultation with Donovan E. Walker, Lead Counsel, Idaho Power Company.