Office of the Secretary
Service Date
December 18, 2012

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 AVOIDED COST RATES.	)	**CASE NO. GNR-E-11-03** **ORDER NO. 32697**

This case began on November 5, 2010, upon a filing by Idaho Power Company, Avista Corporation, and PacifiCorp dba Rocky Mountain Power requesting that the Commission investigate various avoided cost rate issues under the Public Utility Regulatory Policies Act of 1978 (PURPA). Phase I considered eligibility to published avoided cost rate contracts. In February 2011, Phase II undertook an investigation of disaggregation and its effect on published avoided cost rates.

On September 1, 2011, the Commission issued a Notice of Review that initiated this most recent proceeding to investigate the standard terms of PURPA power purchase agreements. Order No. 32352; *Idaho Code* § 61-503. This investigation (Phase III) was not limited to the surrogate avoided resource (SAR) and Integrated Resource Planning (IRP) methodologies for calculating published avoided cost rates. Topics such as 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 were also at issue.

The Commission set an intervention deadline of September 8, 2011. Order No. 32352. All parties of record from the Commission's Phase II PURPA investigation (GNR-E-11-01) were automatically granted party status. On September 21, 2011, a Notice of Parties was issued. On November 2, 2011, the Commission issued the procedural schedule for this case proposed and agreed to by the parties. Order No. 32388. Direct and rebuttal testimony was filed, legal briefs were submitted and a three-day technical hearing commenced on August 7, 2012. Subsequent settlement discussions were held at the directive of the Commission. Order No. 32617. On October 16, 2012, a partial settlement among some of the parties was submitted to the Commission for approval.

By this Order, and as set out in greater detail below, the Commission sets published and negotiated avoided cost rate parameters. The Commission further establishes and defines numerous contract terms for standard power purchase agreements entered into between regulated utilities and qualifying facilities (QFs).

BACKGROUND

A. The Joint Petition GNR-E-10-04 (Phase I)

On November 5, 2010, Idaho Power Company, Avista Corporation, and PacifiCorp dba Rocky Mountain Power filed a Joint Petition requesting that the Commission initiate an investigation to address various avoided cost issues related to the Commission's implementation of PURPA. While the Commission pursued its investigation, the utilities also moved the Commission to "lower the published avoided cost rate eligibility cap from 10 aMW to 100 kW [to] be effective immediately. . . ." *Id. citing* Joint Petition at 7. When a QF project is larger than the eligibility cap set for access to *published* avoided cost rates, the avoided cost rates for the project must be individually negotiated by the QF and the utility using the Integrated Resource Planning (IRP) Methodology.[1] Order No. 32176.

On December 3, 2010, the Commission issued Order No. 32131 declining the utilities' motion to immediately reduce the published avoided cost rate eligibility cap from 10 aMW to 100 kW. Order No. 32131 at 5. However, the Order did notify parties that the Commission's decision regarding the motion to reduce the published avoided cost eligibility cap would become effective on December 14, 2010. *Id.* at 5-6, 9.

Based upon the record in the GNR-E-10-04 case, the Commission subsequently found that a "convincing case has been made to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW <u>for wind and solar only</u> while the Commission further investigates" other avoided cost issues. Order No. 32176 at 9 (emphasis in original). The Commission also announced its intent to initiate additional proceedings to investigate and address the disaggregation of large projects. *Id.* at 11.

[1] The purpose of utilizing the IRP Methodology for large QF projects is to more precisely value the energy being delivered. *Id.* at 10. The IRP Methodology recognizes the individual generation characteristics of each project by assessing when the QF is capable of delivering its resources against when the utility is most in need of such resources. Utilization of the IRP Methodology does not negate the requirement under PURPA that the utility purchase the QF energy.

On reconsideration, the Commission affirmed its decision to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW for wind and solar projects. Order No. 32212. Thus, the eligibility cap for published avoided cost rates for wind and solar QF projects was set at 100 kW effective December 14, 2010. No party appealed the decision to reduce the eligibility cap.

B. Disaggregation GNR-E-11-01 (Phase II)

On February 25, 2011, consistent with its stated intent to investigate the issue of disaggregation, the Commission issued a combined Notice of Inquiry, Notice of Intervention Deadline, Notice of Scheduling, and Notice of Technical Hearing. Order No. 32195. Specifically, the Commission solicited information and initiated an investigation of a published avoided cost rate eligibility cap structure that: (1) would allow small wind and solar QFs to avail themselves of published rates for projects producing 10 aMW or less; and (2) would prevent large wind and solar QFs from disaggregating into small projects in order to obtain published avoided cost rates that exceed a utility's actual avoided cost. *Id.*

In initiating Phase II, we stated that "[t]his Commission is supportive of all small power producers contemplated by PURPA, including wind and solar, and it is not the Commission's intent to push small wind and solar QF projects out of the market." Order No. 32176 at 11. The Commission was concerned that large QF projects were disaggregating into smaller QF projects in order to be eligible for published avoided cost rates that may not be just and reasonable to the utility customers nor in the public interest. Order No. 32195 at 3. The purpose of distinguishing between small and large QFs with the application of the IRP Methodology for large QF projects is to more precisely value the energy being delivered to the utility. *Id.* at 1.

After careful consideration, the Commission ultimately determined that it was appropriate to maintain the 100 kW eligibility cap for published avoided cost rates for wind and solar QFs. Order No. 32262. Wind and solar projects larger than 100 kW are still entitled to PURPA contracts with avoided cost rates calculated through use of the IRP Methodology. The Commission found that any attempt to implement criteria in an effort to prevent disaggregation "would be met by attempts to circumvent such criteria." *Id.* at 8. The Commission emphasized that PURPA and this State's published rate structure were never intended to promote large scale wind and solar development to the detriment of utility customers. We further found that a 100 kW threshold for wind and solar QFs would provide a certainty to the parties in negotiations that disaggregation criteria would not. *Id.* "While we recognize the impact that this decision will have on small wind and solar projects, it would be erroneous, and illegal pursuant to PURPA, for this Commission to allow large projects to obtain a rate that is not an accurate reflection of the utility's avoided cost for the purchase of the QF generation." *Id.*, *citing Rosebud Enterprises v. Idaho PUC*, 128 Idaho 609, 623, 917 P.2d 766, 780 (1996), *citing Connecticut Light & Power Co.*, 70 FERC 61,012 (1995), *reconsid. denied*, 71 FERC 61,035 (1995).

At the conclusion of the Phase II case the Commission stated its intent to initiate additional proceedings to allow the parties to investigate and analyze both the SAR Methodology and the IRP Methodology (GNR-E-11-03, Phase III). On September 1, 2011, the Commission issued a Notice of Review to investigate the standard terms of PURPA power purchase agreements.

C. GNR-E-11-03 (Phase III) Procedural History

The Commission initiated Phase III to investigate various PURPA topics including, but not limited to: the surrogate avoided resource (SAR) methodology, the Integrated Resource Planning (IRP) Methodology, the dispatchability of varying resources, curtailment options, integration costs, renewable energy credits, delay security and liquidated damages, timing and schedule of negotiations, and consideration of contract milestones. Order No. 32352.

The Commission set an intervention deadline of September 8, 2011. All parties of record from the Phase II investigation (GNR-E-11-01) were automatically granted party status in Phase III. *Id.* at 5. On September 21, 2011, a Notice of Parties was issued.[2] On November 2, 2011, the Commission issued a procedural schedule proposed and agreed to by the parties. Order No. 32388. In accordance with the schedule, the utilities filed their individual direct testimonies on January 21, 2012.

On March 12, 2012 (prior to the filing of direct testimony by Commission Staff and Intervenors), Idaho Power filed a Motion for Temporary Stay of Its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities. Idaho Power argued that its prefiled testimony established *prima facie* proof that Idaho Power's current avoided cost rates were not accurate; and that without adequate interim relief from its obligation to purchase, Idaho Power

[2] Several parties were also granted intervenor status after the deadline for intervention had passed.

customers were likely to suffer substantial harm. The Company asserted that the balance of harms favored granting interim relief and that good cause existed to grant immediate relief on an interim basis. Idaho Power filed affidavits in support of its Motion.

On March 14, 2012, Rocky Mountain Power filed a Request to Join and Response to Idaho Power's Motion. The Idaho Conservation League, Snake River Alliance, Exergy, and J.R. Simplot Company each filed responses opposing Idaho Power's Motion and asked that the request for a stay be dismissed in its entirety. In order to give all parties an adequate opportunity to respond to the assertions made by Idaho Power, but in consideration of the expedited nature of Idaho Power's request, the Commission convened an oral argument on March 21, 2012. Order No. 32495.

On March 22, 2012, the Commission issued Order No. 32498 denying Idaho Power's Motion for a Temporary Stay of its mandatory purchase obligation. However, the Commission found that the avoided cost rate methodologies "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 at 2. Therefore, the Commission ordered that, effective March 21, 2012, and continuing until the Commission issues its final Order in Phase III, "contracts for all projects over 100 kW entered into by Idaho Power and presented to this Commission for approval will be individually evaluated with regard to all terms contained therein." *Id.*

Thereafter, direct testimony was filed by Commission Staff and numerous intervenors. On July 6, 2012, rebuttal testimony was simultaneously filed by all parties and subsequent legal briefs were also submitted. A three-day technical hearing convened on August 7, 2012. The following parties appeared by and through their respective counsel or representative:

Avista Corporation	Michael G. Andrea, Esq.
Idaho Power Company	Donovan Walker, Esq. Jason Williams, Esq.
PacifiCorp dba Rocky Mountain Power	Daniel Solander, Esq.
Commission Staff	Kristine Sasser, Esq.

Northwest and Intermountain Power Producers Coalition (NIPPC); Clearwater Paper Corp; J.R. Simplot Co.; Exergy Development Group of Idaho, LLC; Grand View Solar II; Board of County Commissioners of Adams County	Peter J. Richardson, Esq. Gregory M. Adams, Esq.
Dynamis Energy, LLC; Renewable Energy Coalition	Ronald L. Williams, Esq.
Intermountain Wind, LLC; Idaho Windfarms, LLC; Renewable Northwest Project; Ridgeline Energy, LLC	Dean J. Miller, Esq.
North Side Canal Company; Twin Falls Canal Company; Big Wood Canal Company; American Falls Reservoir District No. 2	Tom Arkoosh, Esq.
Idaho Conservation League	Benjamin J. Otto, Esq.
Snake River Alliance	Ken Miller
Idaho Wind Partners I, LLC	Deborah E. Nelson, Esq.
Mountain Air Projects, LLC	Michael J. Uda, Esq. *Pro hac vice*
Interconnect Solar Development	Bill Piske
Blue Ribbon Energy	Aaron Jepson, Esq.
Birch Power Company	Ted Sorenson
Energy Integrity Project	Tauna Christensen

Following the technical hearing, settlement discussions were held at the directive of the Commission. Order No. 32617. A partial settlement was negotiated and submitted to the Commission for consideration. On October 16, 2012, the Commission issued a Notice of Partial Settlement and Request for Comment. Order No. 32665. Parties and the public were given until October 25, 2012, to submit comments regarding the terms of the Settlement Stipulation. Requests for intervenor funding were submitted by Big Wood Canal and American Falls Reservoir; ICL; and North Side and Twin Falls Canal Companies.

By this Order, and as set out in greater detail below, the Commission modifies published (SAR) and negotiated (IRP) avoided cost rate methodologies. The Commission further establishes and adopts numerous contract terms for power purchase agreements entered into between regulated utilities and QFs consistent with PURPA and FERC regulations.

D. PURPA and Avoided Cost Rates

Congress enacted PURPA in 1978 in response to a national energy crisis. "Its purpose was to lessen the country's dependence on foreign oil and to encourage the promotion and development of renewable energy technologies as alternatives to fossil fuels." Order No. 32580 at 3, *citing FERC v. Mississippi*, 456 U.S. 742, 745-46 (1982). To encourage the development of renewable facilities, PURPA requires that electric utilities purchase the power produced by designated qualifying facilities (QFs). "This mandatory purchase requirement is often referred to as the 'must purchase' provision of PURPA." *Id.*, 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a).[3]

Under the must purchase provision, the rate a utility must buy the power produced by the QF is generally referred to as the "avoided cost" rate. "The avoided cost rate represents the 'incremental cost' to the purchasing utility of power which, but for the purchase of power from the QF, such utility would either generate itself or purchase from another source." Order No. 32580 at 3 *citing Rosebud Enterprises v. Idaho PUC*, 128 Idaho 624, 917 P.2d 781 (1996); 18 C.F.R. § 292.101(b)(6). The Idaho Supreme Court has held that the Commission has the authority to implement PURPA and set the avoided cost rates. *Rosebud*, 128 Idaho at 612, 917 P.2d at 769; *A.W. Brown v. Idaho Power Company*, 121 Idaho 812, 814, 828 P.2d 841, 843 (1992). In other words, PURPA requires that utilities buy the power output from QFs under a federal rate mechanism (i.e., avoided costs) that is determined and implemented by state utility commissions.

DISPUTED ISSUES

A. Surrogate Avoided Resource (SAR) Methodology

PURPA and its implementing regulations require that published/standard avoided cost rates be established and made available to QFs with a design capacity of 100 kW or less. 18 C.F.R. § 292.304(c). This Commission has utilized the SAR Methodology for computing published avoided cost rates since the State began implementing PURPA. The SAR

[3] There are exceptions to the must purchase provision but they are not applicable in this case.

Methodology estimates a utility's avoided costs to be applied to QF generation by calculating the cost of a surrogate avoided resource – currently the surrogate used is a natural gas-fired combined-cycle combustion turbine (CCCT). Modifications to the methodology have occurred over time. Input variables and price assumptions have been updated and modified in order to ensure that the published avoided cost rates are an accurate reflection of a utility's avoided cost. A QF's eligibility to published rates has ranged from the minimum requirement of a project producing 100 kW or less to projects as large as 10 MW obtaining a published rate contract.

Currently, for Avista and Rocky Mountain Power, published avoided cost rates are available for wind and solar projects producing 100 kW or less. All other resource types in Avista and Rocky Mountain Power's service territories must generate 10 aMW or less to be eligible for published rates. As of March 21, 2012, all QFs contracting with Idaho Power for the sale and purchase of energy under PURPA, regardless of resource type, must generate 100 kW or less to be eligible for published rates. Order No. 32498. All QF projects generating more energy than what is permitted for a published avoided cost rate contract are eligible under the IRP Methodology to avoided cost rates based on the specific characteristics of each project.

1. Utilities. Avista and Rocky Mountain Power urge the Commission to maintain the 100 kW published rate eligibility threshold for wind and solar resources. These utilities reason that using the SAR Methodology for small projects provides a simple and transparent means of pricing and negotiation that minimizes transaction costs and allows small QFs to build projects. Tr. at 187. Conversely, the utilities argue that, as the size and capacity of a project grows, the appropriateness of the SAR Methodology diminishes. Rocky Mountain Power explains that this is because a small project does not materially impact a utility's load and resource plan. *Id.* at 189. The valuation of energy from a larger project must take into consideration the utility's need for the energy at the times when the resource is able to produce it because of the substantial impact that a large project has on a utility's load and resource balance.

Avista and Rocky Mountain Power further contend that resources other than wind and solar with a nameplate capacity of 10 MW or less be eligible for published avoided cost rates. These utilities argue that a 10 aMW threshold, as is currently used, can be manipulated by "creative developers" to obtain eligibility to published rate contracts – as evidenced by disaggregation. *Id.* at 91-92. The utilities maintain that limiting published rates to smaller projects with a nameplate capacity of 10 MW or less would limit arbitrage opportunities without compromising the intent of PURPA. *Id.* In addition, Avista supports annual updates of the fuel price forecast utilized within the SAR model using the DOE EIA Annual Energy Outlook. *Id.* at 92.

Avista also supports separating energy and capacity payments and only paying a QF for capacity when the energy is needed to serve a utility's load. Avista argues that making capacity payments to a QF when the energy is not needed is a violation of the avoided cost principle that the utility only pay what costs it avoids by purchasing the QF generation instead of producing the energy itself. Tr. at 59. Avista reasons that if a QF cannot be relied upon to generate energy during the utility's peak load hours, then the utility will be forced to build or otherwise procure a resource that can be utilized to serve customers during those peak load hours. *Id.* at 75. Thus, a utility's capacity needs are not avoided by purchase of such QF generation. Resources must still be built to meet the utility's capacity needs. If capacity needs are not being met by the QF resource then, Avista argues, the QF should not be compensated with capacity payments.

Avista supports use of load and resource balances as reported in each utility's IRP in order to determine when the utility becomes capacity deficient. *Id.* at 68. Capacity payments would be included in payment of avoided costs in the year in which a utility's load and resource balance shows that the utility is capacity deficient. Avista also suggests that load changes between IRP filings (i.e., a new load forecast, new contract obligations, deliveries incurred since the publication of the IRP), should be considered when determining a utility's capacity needs. *Id.* Rocky Mountain Power proposes that capacity payments be included in avoided costs coincident with the timing of its next deferrable resource. *Id.* at 207.

Idaho Power maintains that the IRP Methodology should be used to set both published and negotiated avoided cost rates. *Id.* at 483. Idaho Power argues that the SAR Methodology does not correctly model the actual PURPA resource because the SAR utilizes a CCCT in its calculation and assumes a very high annual capacity factor. Idaho Power further states that the SAR does not properly value the energy at the times it is delivered to the utility. Idaho Power contends that different types of generating resources have different operating characteristics that offer different value to the utility and should be considered when setting an avoided cost rate. Finally, Idaho Power asserts that the current published rates are not updated on a regularly scheduled basis and, therefore, do not take into account changes in resources as they are added to a utility's portfolio. For these reasons, Idaho Power does not support continued used of the SAR Methodology in establishing published avoided cost rates.

Idaho Power recommends that the published rates be derived from the IRP Methodology based on resource type and updated every two years as each IRP is compiled and presented for Commission review. Idaho Power states that this is a more accurate method for calculating avoided cost rates because it allows the utility to assign pricing within smaller time frames which provides a better estimate of the actual value of the energy being delivered. Tr. at 484. Idaho Power continues to maintain that published rates be available to only projects producing 100 kW or less. Idaho Power states that, because the published rates would be updated only every two years, making published rates available to only truly small QF projects reduces the risk to the utility's customers that they would be paying too much for the energy produced.

Idaho Power maintains that an annual update of fuel price forecasts, through use of the federal Energy Information Administration (EIA) Annual Energy Outlook, is an improvement over the method currently used, but the utility suggests that the Commission go a step further to also adopt the EIA's short-term forecast. Idaho Power contends that the EIA annual forecast can become rapidly outdated in a quickly shifting natural gas market. *Id.* at 493. Idaho Power supports payment of a capacity component at the time in which each utility's IRP shows a capacity deficiency. Idaho Power maintains that this treatment is consistent with the utility's requirement that it show resources are "used and useful" in order to seek recovery from customers. Idaho Power also argues that it "is an appropriate way to account for the ability of a QF to come on-line at any time irrespective of a utility's need." *Id.* at 513.

2. <u>Commission Staff</u>. Commission Staff maintains that the current SAR Methodology, with some modifications, should continue to be used to set the published avoided cost rates for PURPA contracts. Staff contends that eligibility to published rates be set at 100 kW for wind and solar to address the unique characteristics of these resources that allows them to disaggregate and receive higher, less accurate avoided cost rates for their energy. Staff argues that, for resources other than wind and solar, a 10 aMW threshold has been utilized successfully for many years and should be maintained.

Staff proposes that the Commission update the fuel price forecast used in the SAR model annually using the EIA Annual Energy Outlook instead of the current process utilizing updates issued by the Northwest Power and Conservation Council. Staff contends that updating fuel prices on a regularly scheduled, annual basis will produce a more accurate SAR calculation. Staff further argues that the SAR model should be modified to account for a utility's surplus energy periods in order to produce more accurate avoided cost rates. Staff proposes that the SAR model identify when a utility is deficient in energy, in capacity, or both. Tr. at 1061. If a utility is not deficient in energy when a QF delivers then the QF's energy payment should be reduced by the cost of transmission and losses.

Staff also proposes that capacity payments vary based on resource type. By allowing capacity payments to differ based on resource type, QF development would be encouraged or discouraged based on when the energy is deliverable to the utility. *Id.* at 1062. QFs that provide generation during peak hours (when the utility is most in need to serve its customers) would be compensated based on their ability to deliver energy when it is most needed. Under this method of valuing capacity, canal drop hydro rates are considerably higher than other resources because canal drop projects provide capacity during peak summer hours and their capacity payment is spread over relatively few total hours. *Id.* at 1064. Wind projects receive the lowest rates because of wind's low on-peak capacity factor. *Id.* at 1065.

Staff maintains that, by using a QF's nameplate capacity in the SAR calculation, capacity payments can be determined based on a project's ability to incrementally contribute to a utility's capacity deficiency. Tr. at 1067-68. Through use of this method, a QF would be paid earlier, but at an incremental rate, for its capacity contribution to the utility. This method also recognizes that there are times when capacity provided in only one season does, in fact, translate into capacity avoided by the utility. *Id.* at 1068. Under Staff's approach, capacity deficiency would be identified based on load and resource balances found in each utility's IRP plan.

3. Intervenors. Northside Canal Company, Twin Falls Canal Company and Renewable Energy Coalition ("the Canal Companies") filed joint testimony in this proceeding. The Canal Companies propose that all projects with a nameplate capacity of 10 MW or less be eligible for published avoided cost rate contracts. The Canal Companies maintain that a 100 kW threshold for eligibility to published rates for all resource types would force virtually every project to be negotiated through use of the IRP Methodology which could ultimately impact a project's viability. Tr. at 843-44. Based on this reasoning, the Canal Companies contend that a 10 MW nameplate eligibility cap for published avoided cost rates would reasonably allow

smaller QF projects to develop without the administrative and transactional complications of negotiations through the IRP Methodology. *Id.* The Canal Companies further maintain that a 10 MW nameplate eligibility threshold for published rates is consistent with this Commission's past practice.

The Canal Companies argue that positions advocating a 100 kW eligibility cap really amount to a pricing issue under the SAR Methodology that can be fixed by modifying the manner in which the SAR prices are determined. Tr. at 845. Consequently, the Canal Companies oppose the changes to avoided cost calculations proposed by Idaho Power. The Canal Companies maintain that, as long as consistent assumptions are used under both methodologies, the SAR and IRP methodologies should result in similar avoided cost calculations. *Id.* at 852. They believe that either method is appropriate, when applied consistently, and would result in reasonable avoided cost prices. *Id.* at 853.

The Canal Companies also support annual updates, using the EIA Annual Energy Outlook, for the fuel price forecast used in the SAR model. *Id.* at 886. The Canal Companies further support Staff's proposal regarding use of a QF's nameplate capacity in the SAR calculation in order to derive capacity payments that can be determined based on a project's ability to incrementally contribute to a utility's capacity deficiency. *Id.* at 890. They "find Staff's revised model a simple, transparent and straightforward approach to determine capacity need, allocation and pricing." *Id.*

Clearwater Paper, Exergy Development Group, and J.R. Simplot ("C/E/S") filed joint testimony in this proceeding. C/E/S maintains that the SAR Methodology "has been a successful, transparent and effective method for estimating a utility's avoided cost rates." Tr. at 926-27. These companies support the continued use of the SAR Methodology for calculating published avoided cost rates. In addition, C/E/S contends that all projects producing 10 aMW or less should be eligible to published avoided cost rates regardless of the QF resource. *Id.* at 957.

C/E/S maintains that a CCCT is more appropriate than a SCCT in setting a proxy under the SAR Methodology. The companies argue that combined-cycle units are the "resource of choice" for utilities adding base load plants and, therefore, a CCCT remains the reasonable choice in calculating values with the SAR Methodology. C/E/S also agrees with use of the EIA Annual Energy Outlook for annual updates of the fuel price forecast used in the SAR model. They agree that annual updates to the fuel price forecast provide predictability for all parties and parity in the timing of potential rate increases and decreases. *Id.* at 941. C/E/S further contends that QF projects should be eligible for capacity payments through the entire term of their contracts with no consideration of when a utility becomes capacity deficient. Tr. at 958. C/E/S argues that "denial of capacity payments during a period of claimed surplus does not put a QF facility and a company owned generating plant on an equal footing." *Id.* at 936.

Finally, C/E/S maintains that IRP submissions by the utilities "are becoming increasingly relied upon for a wide number of important regulatory issues." *Id.* at 939. For this reason, C/E/S argues that IRPs should be subject to greater scrutiny and an adjudicated hearing process, with ultimate approval by the Commission before the IRP conclusions are utilized for the calculation of the avoided cost calculation rates.

Commission Findings

1. <u>The Eligibility Cap for Published Rates</u>. Wind and solar are intermittent energy resources with unique characteristics. A 100 MW wind farm or solar project can be broken up into 10 aMW pieces in order to obtain multiple published rate contracts, i.e., disaggregation. When a 100 MW wind or solar project is disaggregated, we find the SAR Methodology no longer produces a rate that accurately reflects the value of the energy to the utility. A 100 MW project is not even eligible under PURPA nor is a utility bound to purchase power from a 100 MW facility under PURPA's "must purchase" provision. 18 C.F.R. § 292.204(a). Therefore, to prevent large projects from disaggregating in order to not only become eligible under PURPA but also obtain published avoided rates, and based on the unique characteristics of wind and solar resources to disaggregate, we find that the eligibility cap for published avoided cost rate contracts for wind and solar projects shall be set at 100 kW or less. Congress intended to allow PURPA cogeneration and small renewable projects to produce and sell power without the burden of being regulated as an electric utility. Congress did not intend for multi-national corporations to fund large wind farms for the benefit of their shareholders and the detriment of the utilities' ratepayers. 18 C.F.R. § 292.304(a). Indeed, PURPA transactions are intended to hold ratepayers harmless. This finding is just and reasonable and consistent with PURPA and FERC regulations.

A QF project producing no more than 10 aMW meets the definition of a small project that does not materially impact a utility's load and resource balance as long as it is, in fact, a single small QF project and not a large project disaggregated to obtain a higher avoided cost rate. The 10 aMW eligibility cap for published rate avoided costs for resources other than wind and solar has proven to be beneficial by allowing for small projects to be developed without unduly or inappropriately burdening ratepayers. This Commission's use of a 10 aMW eligibility cap for published rate contracts has encouraged PURPA projects, promoted renewable energy development in Idaho and, when used as it was intended, kept ratepayers indifferent. Utilizing a 10 MW nameplate eligibility cap for published avoided cost rate contracts, as proposed by Avista and Rocky Mountain Power, is a more restrictive approach and would limit the availability of published avoided cost rates to only very small projects. This Commission is confident that, with other changes to the avoided cost methodologies incorporated in this Order, changing eligibility from 10 aMW for resources other than wind and solar is unnecessary at this time. We find that a 10 aMW eligibility cap for access to published avoided cost rates for resources other than wind and solar is appropriate to continue to encourage renewable development while maintaining ratepayer indifference. Maintaining a 10 aMW eligibility cap is also consistent with our long history of encouraging PURPA projects and renewable energy generation in Idaho.

We acknowledge Idaho Power's efforts to devise an alternative wholly different than the SAR method currently used to obtain published avoided cost rates. However, we are not prepared to abandon the SAR method entirely. As is evident from this Commission's history with PURPA, avoided cost methodologies, inputs and calculations need to be reviewed and refreshed periodically. The genesis of this case in November 2010 came from Idaho Power being overwhelmed with requests by QFs for published avoided cost rate contracts. The vast majority of those projects were large wind farms that were disaggregating in order to take advantage of the then 10 aMW published rates. Under PURPA's must purchase obligation, Idaho Power was forced to accept hundreds of megawatts of electricity at rates intended for small projects producing 10 aMW or less. These large projects had the potential to drastically affect the utility's load and resource balance and raise customer rates contrary to the mandate in PURPA that they be held harmless. The valuation of energy from these large projects must take into consideration the QF's ability to generate energy at a time when the utility most needs the energy to serve its load. This valuation can be accurately accomplished through application of the IRP Methodology. We find that, by maintaining an eligibility cap of 100 kW or less for wind and solar projects, Idaho Power's concerns regarding disaggregation are mitigated.

2. Separate Capacity and Energy Rates. A QF that provides generation during peak hours when the utility is most in need of power to serve its customers should be compensated based on the QF's ability to deliver during peak hours. This structure comports with the purpose and intent of PURPA that a utility pay a QF the costs it avoids by not having to build or procure alternative energy. 18 C.F.R. 292.304(b)(2). Payments for both energy and capacity must be part of this consideration. Although the current SAR model merges energy and capacity payments into a single avoided cost rate, this Commission has previously approved separate energy and capacity payments as consistent with the intent and objectives of PURPA. PURPA requires that the utility purchase the energy produced by a QF. Paying for a resource's ability to provide the utility with capacity that the utility needs to reliably serve its customers encourages development of resources that truly allow the utility to avoid the costs of building new generation.

The utilities, Commission Staff, and several intervenors support the use of a separate capacity payment to appropriately value the power being produced and delivered by a QF. We find that implementation of a separate resource-specific capacity factor is an appropriate way to value when a QF is able to generate and deliver energy to a utility. The value of all renewable resources is not equal. If a QF is primarily allowing a utility to avoid energy generation during non-peak hours, but not providing capacity during peak hours, then the utility is not avoiding the cost of building new plant. Generation will ultimately have to be built to provide the capacity necessary to reliably serve customers during peak load hours. Consequently, we find it reasonable to assign a value to a QF resource's ability to provide such capacity. A QF resource with a high capacity factor is not only providing the utility with energy, but also capacity that will allow the utility to avoid having to construct new generation to serve its customers during peak load hours.

Intervenors to this case have selectively used the term "equal footing" to refer to the way utilities are treated versus the way QFs are treated. Intervenors suggest that denial of capacity payments does not put a QF on "equal footing" with a utility. To the contrary, a consideration of utility need and potential surplus energy does treat a QF much like a utility-owned resource. A utility cannot be compensated by its customers for energy produced from a generating facility until the utility establishes the need for such new generation. *Idaho Code* §§

61-526, 61-528, and 61-541. *See also* Case No. U-1006-265, Order No. 20610; Case No. IPC-E-12-14, Order No. 32585; and Case No. PAC-E-11-12, Order No. 32432.

Moreover, "equal footing" is not a legal standard required by PURPA nor applied by this Commission. The legal standard for an appropriate determination of avoided cost rates is clearly defined by PURPA. Rates for purchases from a QF shall "(i) be just and reasonable to the electric consumer of the electric utility and in the public interest; and (ii) not discriminate against qualifying cogeneration and small power production facilities." 18 C.F.R. § 292.304(a)(1). "Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases." *Id.* at § 292.304(a)(2). Avoided costs are those costs which a public utility would otherwise incur for electric power, whether that power was purchased from another source or generated by the utility itself. 18 C.F.R. § 292.101(b)(6). PURPA allows QFs to obtain a rate equivalent to the utility's avoided cost, a rate that holds utility customers harmless – not a rate that puts QFs on "equal footing" with the utility. PURPA requires public utilities to purchase generation from QFs without regard for whether the utility needs the energy. If a QF resource provides energy but not capacity, then the utility is not avoiding a portion of costs that will be required to build generation that provides capacity. For this reason, we find it reasonable, appropriate and in the public interest to compensate QFs separately based on a calculation of not only the energy they produce, but the capacity that they can provide to the purchasing utility.

We find that utilizing a QF's nameplate capacity in the SAR calculation is a reasonable approach that provides payment to QFs for capacity based on a project's ability to incrementally contribute to a utility's capacity deficiency. We further find it appropriate to identify each utility's capacity deficiency based on load and resource balances found in each utility's IRP.

3. <u>Line Loss</u>. We decline proposals to discount QF energy payments for transmission and line loss when a utility is energy surplus. These costs are difficult to quantify and may not exist in all cases. Therefore, we find that, without more certainty, it would be inappropriate to discount QF energy payments for such costs.

4. <u>Annual SAR Updates</u>. We further find that, in order to remain flexible and responsive to the fluctuations in gas prices, it is appropriate to annually update the SAR model with the most recent gas forecasts provided by EIA's Annual Energy Outlook. Based on the

timing of the release of EIA's annual report, and as proposed by Dr. Reading, we find it appropriate to update rates with EIA's most recent gas forecasts on June 1 of each year.[4]

5. SAR Type. We further find it reasonable to continue to utilize a combined-cycle combustion turbine (CCCT) surrogate as the basis for all calculations in the SAR model. The SAR Methodology is intended to represent a surrogate base load natural gas resource. Simple-cycle combustion turbines (SCCT) are primarily utilized for meeting a utility's peak loads; CCCTs provide base load energy. The proposals of some of the parties to use an SCCT for calculating capacity value and a CCCT to compute energy value would create a very awkward and not representative surrogate resource. Consequently, we decline to utilize a SCCT.

B. Integrated Resource Plan (IRP) Methodology

The IRP Methodology had its inception in 1995 (Case No. IPC-E-95-9) but has seldom been utilized – even by large QF projects – because the avoided cost rate produced through use of the IRP Methodology for certain types of resources has not, historically, been as favorable as the published avoided cost rates. Consequently, large wind QF projects were being broken into smaller pieces in order to meet the eligibility cap requirement for access to published avoided cost rate contracts, i.e., disaggregation. *See* PAC-E-10-01 through 10-05; IPC-E-10-51 through 10-55; IPC-E-10-56 through 10-58; IPC-E-10-59 and 10-60; and IPC-E-10-61 and 10-62. When this case was initiated by the utilities in November 2010, only two IRP-based rate QF power purchase agreements had been presented and approved by this Commission. Therefore, the IRP Methodology has not had the benefit of adjustments over time to ensure that the calculation produces an accurate representation of the utility's avoided cost. The rates produced pursuant to the IRP Methodology were not called into question until eligibility to published rate contracts was restricted.

The IRP Methodology takes into account many different variables and produces a result based on each individual utility's need for energy. More specifically, the IRP method assesses the value of each QF project in terms of its capability to deliver resources in relation to the timing and magnitude of the utility's need of such resources.

1. Utilities. Avista proposes that, under the IRP Methodology, the QF only receive capacity payments after the utility becomes capacity deficient. Avista maintains that, when the

[4] Calculations for resources under the SAR Methodology – utilizing EIA's most recent Annual Energy Outlook – are attached.

utility is in surplus, it does not avoid any capacity by purchasing output from the QF. Because the utility does not need the capacity, the capacity value of QF power during surplus periods should be zero. Tr. at 80. In addition, Avista argues that a QF's energy payments should be discounted during times of utility surplus to account for the costs of transmitting surplus power and selling it in the market. "[T]ransmission has value to customers as it can be resold by Avista's transmission group to third parties. Reserving transmission for the purpose of moving QF power to market would reduce those transmission revenues." *Id.*

Rocky Mountain Power maintains that the IRP Methodology, "as established in IPC-E-95-09, is an appropriate method to assess the value of a QF project in terms of its capability to deliver its resource when the Company is in need of such a resource, and is reflective of the value of the QF to the Company and its customers." Tr. at 188. Rocky Mountain Power argues that, with a 100 kW eligibility cap in place for wind and solar resources, the previously adopted SAR and IRP methodologies continue to provide an accurate means of calculating avoided cost prices for QFs.

Rocky Mountain Power proposes that modeling inputs for the IRP Methodology be updated contemporaneously at the time of each pricing request in order to ensure the most up-to-date modeling assumptions. Rocky Mountain Power asserts that its IRP process already accounts for the incremental need and cost of capacity on its system. Its capacity payments are determined based on the timing of the next deferrable resource in its IRP preferred portfolio. *Id.* at 199.

Idaho Power maintains that the IRP Methodology should be used for setting both published and negotiated avoided cost rates. Tr. at 477. Idaho Power contends that the IRP Methodology is appropriate to use for all PURPA contracts because it sets a more accurate value on the energy that a QF delivers to the utility based on the time that the energy is delivered. Idaho Power argues that the IRP Methodology is flexible and can be updated more frequently as conditions and assumptions change. *Id.* at 484. The Company explains that the IRP model can be updated as each incremental resource is added to a utility's generation portfolio. *Id.*

Idaho Power explains that a resource that is able to deliver energy during heavy load hours when the utility is most in need of the energy would receive a higher overall price than a resource that is primarily able to deliver energy during light load hours when the utility is already surplus and least in need of the energy to serve its customers. As it is currently applied, Idaho

Power's IRP Methodology does not include an avoided cost for capacity until the first month that its load and resource balance shows a peak-hour deficit based on existing and committed resources as identified in its IRP. *Id.* at 474.

2. Commission Staff. Staff maintains that the IRP Methodology can produce more accurate avoided cost rates with a few modifications. Staff argues that the IRP rates should not include any value for QF capacity in years when the utility has surplus capacity. Tr. at 1079. "The proper mechanism for accounting for utility need is not to relieve utilities of their obligation to purchase, but instead to establish prices for capacity and energy that properly recognize the utilities' need, or lack of need, for capacity and energy. By not paying for capacity during surplus periods, utilities would be paying what amounts to a more accurate reflection of a true avoided cost." Tr. at 1090. Staff further maintains that energy rates be reduced by the cost of transmission and losses during surplus periods. *Id.* at 1085. Staff notes that, as it is presently applied, each utility's IRP model accounts for whether the utility is in need of capacity. "In the methods used by each utility, none assign capacity value to QFs in years when the utility is in a surplus condition." *Id.* at 1091.

Finally, Staff proposes that a simple-cycle combustion turbine (SCCT) be used as the basis for computing capacity value under the IRP Methodology for all resource types. Staff argues that "the proper resource to use as the basis for computing capacity value is the lowest cost resource that could be added to provide capacity equivalent to what would otherwise be provided by the QF." *Id.* at 1093. Because Staff proposes to compute energy and capacity separately, using a SCCT is most appropriate because it represents the lowest cost, nearly capacity-only resource. *Id.*

In order to produce a more accurate avoided cost rate, Staff recommended that utilities be permitted to update fuel price forecasts and load forecasts annually – between IRP filings. Staff further recommended that long-term contract commitments (including QF contracts) be incorporated once a contract has been signed by the QF and submitted to the utility for signature. *Id.* at 1099. "PURPA contracts that are terminated, expire, or that have approved modifications of their online dates should also be immediately considered in the load resource balance." *Id.* at 1100.

3. Intervenors. The Canal Companies support use of the IRP Methodology as long as consistent assumptions are used in both the SAR and IRP methods. Tr. at 852. The Canal

Companies admit that while "the integrated resource method may not be as transparent as the surrogate resource method, it can do a better job of taking into account a utility's needs by incorporating all the expected loads and resources over the contracting planning horizon." *Id.* at 852-53. They support two updates to the model between IRP filings: annual updates for natural gas prices and updates for new, executed QF agreements. *Id.* at 859-60.

The Canal Companies maintain that it is reasonable for a utility to include only the cost of energy in its avoided cost payment to new QFs until the utility shows a need for capacity. Tr. at 867. However, they argue that existing QFs entering into contract extensions or renewals should be paid full capacity value for the entire term of an extension or renewal. "These resources have not caused the projected short-term surplus and should not be penalized in the form of reduced capacity value payments in a subsequent follow-on PPA." *Id.* at 869. The Canal Companies further maintain that utilizing a SCCT to determine a QF's capacity value is appropriate for Idaho Power.[5] *Id.* at 866.

C/E/S only supports use of the IRP Methodology after "each utility's IRP is fully considered and approved through the hearing process." *Id.* at 957. C/E/S proposes that changes to variable inputs only be allowed with each approved IRP – with the exception of natural gas prices which should be updated annually. *Id.* at 958. C/E/S further proposes that capacity payments be included for the full term of the contract with no consideration of utility surplus or deficit.

Commission Findings

The IRP Methodology recognizes the individual generation characteristics of each project by assessing when the QF is capable of delivering its resources against when the utility is most in need of such resources. We find that the resultant pricing is reflective of the value of the QF energy being delivered to the utility. We are not convinced, nor has sufficient evidence been presented, that the utilities' use of different models to derive IRP-based rates (i.e., AURORA vs. GRID) produces substantially different rates. To the contrary, the evidence shows that energy rates calculated by the utilities for different resources are substantially similar between the utilities. Therefore, we find that the IRP models used by each individual utility produce reasonable avoided cost rates consistent with PURPA and FERC regulations.

[5] The Canal Companies are not recommending changes to Avista's or Rocky Mountain Power's avoided capacity resource. Tr. at 867.

Idaho Power proposed revisions to the IRP Methodology that focus on identifying the incremental costs that its system would incur, i.e., a single-run simulation, rather than its current methodology that is primarily predicated on making surplus sales at the future market prices developed within the AURORA model, i.e., a two-run simulation. In order to do this, Idaho Power proposes to use the AURORA model to determine the highest displaceable incremental cost being incurred during each hour of the QF's proposed contract term. The Company claims that its proposed modified methodology better aligns with the definition of avoided cost from federal regulations, and results in a much better estimation of the costs the utility is capable of avoiding.

The Commission finds Idaho Power's proposed modifications to the IRP Methodology reasonable. We agree that the Company's revisions properly focus the determination of avoided costs on incremental costs, not solely on the value of potential market sales. The result, we find, is a more accurate avoided cost. Moreover, we find that the modified methodology comports with the definition of avoided cost contained in FERC regulations. Therefore, we direct Idaho Power, Avista and Rocky Mountain Power to utilize displaceable incremental costs in calculating avoided cost rates under the IRP Methodology.

1. Capacity Deficiency. In computing avoided cost rates under the IRP Methodology, each of the three utilities already employs a two-step approach in which energy and capacity values are computed separately. In calculating a QF's ability to contribute to a utility's need for capacity, we find it reasonable for the utilities to only begin payments for capacity at such time that the utility becomes capacity deficient. If a utility is capacity surplus, then capacity is not being avoided by the purchase of QF power. By including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power. However, we find merit in the argument made by the Canal Companies that contract extensions and/or renewals present an exception to the capacity deficit rule that we adopt today. It is logical that, if a QF project is being paid for capacity at the end of the contract term and the parties are seeking renewal/extension of the contract, the renewal/extension would include immediate payment of capacity. An existing QF's capacity would have already been included in the utility's load and resource balance and could not be considered surplus power. Therefore, we find it reasonable to allow QFs entering into contract extensions or renewals to be paid capacity for the full term of

the extension or renewal. Consistent with our findings under the SAR Methodology, we decline proposals to discount QF energy payments for transmission and line loss when a utility is energy surplus. At this time, it would be inappropriate to discount QF energy payments for such costs.

We further find that a simple-cycle combustion turbine (SCCT) is the most appropriate basis for computing capacity value for all resource types. SCCT's are added to a utility's resource portfolio to satisfy capacity needs. Because energy and capacity are being calculated separately, it is reasonable to use a SCCT because it represents the lowest cost, nearly capacity only resource.

2. Updates. We find that, in order to maintain the most accurate and up-to-date reflection of a utility's true avoided cost, utilities must update fuel price forecasts and load forecasts annually – between IRP filings. For the sake of consistency, these annual updates should occur simultaneously with SAR updates – on June 1 of each year. In addition, it is appropriate to consider long-term contract commitments because of the potential effect that such commitments have on a utility's load and resource balance. We find it reasonable to include long-term contract considerations in an IRP Methodology calculation at such time as the QF and utility have entered into a signed contract for the sale and purchase of QF power. We further find it appropriate to consider PURPA contracts that have terminated or expired in each utility's load and resource balance. We find it reasonable that all other variables and assumptions utilized within the IRP Methodology remain fixed between IRP filings (every two years).

C. The IRP Planning Process

The IRP Methodology utilizes inputs determined through the utilities' IRP planning process. Each utility submits an Integrated Resource Plan every two years that details what the utility anticipates its resource needs will be over the next 20 years. A utility's IRP is a flexible document meant to assess the needs of the utility so it can safely and reliably serve its customers.

When it became apparent that the IRP Methodology would be utilized for a growing number of QF projects, the IRP planning process came under attack by opponents of the IRP Methodology. They argue that the IRP planning process is not a collaborative effort and factors used within the IRP Methodology can be manipulated by the utility compiling the Plan. The utilities maintain that the IRP planning process is independently conducted without regard to the impact that particular determinations will have on the IRP Methodology.

Commission Findings

At the outset it is important to note that IRPs submitted by each utility are not "approved" by this Commission. An IRP assesses a utility's long-term energy needs. However, it is axiomatic that a utility's energy needs change over time based on customer growth, availability and cost of resources, environmental considerations and requirements, and other factors. It would not be reasonable, nor to the benefit of customers, to hold a utility to a fixed 20-year projection of its anticipated resource needs. Approval of IRPs by this Commission might imply that we agree with all of the utility's assessments regarding how it will respond to growth over the next 20 years and that we intend to hold the utility to its projections and plans. Such an approach would run counter to the Commission's position that a utility's long-term plan should remain just that – a plan that is flexible and responsive to its customers' needs over time. Hence, the requirement of submitting a 20-year plan to this Commission for review every two years.

The IRP process is a beneficial and worthwhile endeavor by the utilities to objectively and critically evaluate their growing needs for power into the future. We decline to assert more control and regulation over a process that functions well for its intended purpose, i.e., assessment of the utility's long-term needs. However, we acknowledge that some determinations made within the IRP process have an impact on calculations under the SAR and IRP methodologies. Specifically, the IRP process determines when the utility will experience a need for new capacity.

In an effort to address the concerns of QF developers who maintain that a utility could manipulate variables within the IRP planning process in a way that would negatively impact the pricing of capacity paid to a QF, we find it reasonable and fair to subject each utility's determination of capacity deficiency to further scrutiny. Therefore, when a utility submits its Integrated Resource Plan to the Commission, a case shall be initiated to determine the capacity deficiency to be utilized in the SAR Methodology. The capacity deficiency determined through the IRP planning process will be the starting point, and will be presumed to be correct subject to the outcome of the proceeding.

D. Contract Length

Over the years, this Commission has approved QF contracts of varying lengths. The current standard contract length of 20 years was approved by this Commission in 2002 when we found that a 20-year contract would better coincide with the amortization period or planned resource life of the renewable/cogeneration resources being constructed and ensures a revenue stream sufficient to facilitate the financing of QF projects. *See* Order No. 29029.

1. Utilities. Idaho Power proposed that the Commission adopt a maximum contract length of five years. *Id.* at 487. Idaho Power maintains that a 20-year fixed-rate contract unfairly shifts market price risk from the QF developer entirely onto the utility's ratepayers.

2. Commission Staff. Staff supports Idaho Power's proposed five-year contract length for IRP-based contracts. Staff reasoned that long-term contracts have historically been used by this Commission to encourage and boost the development of PURPA projects. Tr. at 1105. However, utilities are not currently in need of the power produced by PURPA QFs and, with present economic conditions, utilities' customers are already struggling to pay their bills. *Id.* Staff argues that it is not this Commission's responsibility to ensure that contract length is long enough for the QF to be able to obtain financing. Further, Staff maintains that it is good public policy for the Commission to utilize tools, such as limiting maximum contract length, in order to control the pace of PURPA development. *Id.*

3. Intervenors. The Canal Companies oppose the implementation of five-year contracts. The Canal Companies characterize five-year contracts as unfair, inequitable, and insufficient for cost recovery. *Id.* at 845. They maintain that the contract term should more closely align with the usable life of the resource. *Id.* C/E/S argues that the current 20-year contract length should be maintained. *Id.* at 958. C/E/S urges the Commission to reject Idaho Power's five-year proposal as contrary to the intent of FERC and detrimental to QF development. *Id.* at 969.

Commission Findings

We find that a 20-year contract length, along with other factors, has been beneficial in encouraging PURPA development in Idaho. We continue to believe that 20-year contracts better coincide with the useful life of the renewable/cogeneration resources. While it is not this Commission's responsibility to ensure a contract length that allows a QF to obtain financing, we find that reducing maximum contract length to five years would unduly hinder PURPA development. That is not the Commission's objective. We believe that, by utilizing other tools to ensure an accurate and up-to-date avoided cost valuation, we can continue to encourage the types of projects that were envisioned by PURPA while maintaining the transparency for ratepayers as PURPA requires. Therefore, we find that a maximum contract length of 20 years is appropriate. The parties to a power purchase agreement are free to negotiate a shorter contract if that would be most suitable for the project. As in the past, this Commission will consider contracts of more than 20 years on a case-by-case basis.

E. Security Deposit/Liquidated Damages

1. Utilities. Avista and Idaho Power urge the Commission to continue allowing utilities to require security deposits in the amount of $45 per kW of nameplate capacity. Avista's witness Clint Kalich testified that adequate delay security is "one of two key protections a utility must have with any [PURPA] developer" to ensure that developer performs under an executed PPA. Tr. at 84. The security deposit provides an incentive to the QF developer to bring the project on-line. If a PURPA developer is not able to meet the commercial operation date specified in its PPA, then "the utility ends up at the last moment having to procure other resources, potentially at higher costs. In the absence of meaningful liquidated damages, the QF developer has a free option to either honor its contractual commitment . . ., or simply cease development where market conditions have changed." *Id.* at 84-85.

Mr. Kalich explained that the second key protection for utilities is the need for "meaningful termination rights if the QF fails to achieve commercial operation within the timeframe established in the PURPA contract." *Id.* at 85. He recommended that each PURPA contract have a standard termination clause which enables the utility to terminate the PPA 180 days after a developer's project has failed to achieve to achieve commercial operation as scheduled in the PPA. He concluded by recommending that the developer be required to post the $45 per kW "liquidated damages deposit at the time that the legally enforceable obligation arises – i.e., when the . . . QF developer executes and returns the tendered contract obligating the utility to purchase" the output from the QF. *Id.* at 86.

Idaho Power also supported a requirement that PURPA developers post delay damage security in the amount of $45 per kW of nameplate capacity. Idaho Power witness Mark Stokes testified that the Commission has addressed the issue of security on numerous occasions when it has been called upon to approve various PPAs. Mr. Stokes argued that the difference between acquiring replacement power and the cost of power in a PPA is not the only measure of damage suffered by a utility when a QF does not bring its facility on-line as scheduled. He noted that there are system operations and planning problems that arise when a QF fails to bring its facilities on-line as scheduled. Tr. at 536. If a QF is allowed to default under the PPA by not bringing its project on-line as scheduled, "then customers are left in a financially disadvantaged position and uncompensated for the price lock and option they extend to the QF project." *Id.*

In its prehearing legal brief, Idaho Power asserted that when a QF resource fails to come on-line as scheduled

> 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 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 [our] system where market liquidity is an issue and prices are almost always higher.

Brief at 29. Thus, damages may be difficult to quantify with precision, but are nevertheless "very real to the utility and its customers." *Id.* at 31. Consequently, Idaho Power asked the Commission to continue allowing utilities to collect delay liquidated damage security.

2. Commission Staff. Staff witness Rick Sterling testified that it was reasonable for utilities to require a security deposit for liquidated damages. Although he stated the Commission has never specified in any of its Orders the timing of when such a security deposit should be due, he found merit in Avista's proposal that the deposit be due when a legally enforceable obligation arises. Tr. at 1111. "It seems fair that if a QF can unilaterally impose a legally enforceable obligation on a utility, the QF should contemporaneously incur a corresponding obligation to perform backed by a posting of required security for liquidated damages." *Id.* at 1111-12. Although he recommended continued use of the liquidated damages provision, he also acknowledged on cross-examination that he was not necessarily opposed to using an "actual damages type of an approach if it could be done practically and fairly." Tr. at 1178.

3. Intervenors. C/E/S witness Dr. Don Reading testified that rather than basing liquidated damages on a $45 per kW amount, liquidated damages should be based on an actual estimate of the likely damages that the utility would incur if the QF is not operational as scheduled in the contract. In the event of a QF developer's default, the "intent should be to keep the utility and its customer[s] whole in the event of a default." Tr. at 960. In calculating delay

damages, Dr. Reading recommended three factors in setting liquidated damages. First, in the event of a QF default, the estimate of damages should be calculated as the difference between the rates in the PPA "and the actual cost for replacement power during the period the QF's delay default forces the utility to secure replacement power." Tr. at 961. The replacement price would include the cost at the relevant market hub plus the necessary transmission and administrative costs to secure that replacement power. *Id.* Second, although he recognized that PURPA contracts typically have 20-year terms, he suggested that paying damages should be limited to a period of time "for the utility to make alternative long-term arrangements to secure that amount of power." *Id.* Third, he recommended that if a security deposit is required, that such deposit not be required until "after the PPA is signed and approved by the Commission." Tr. at 962.

The Canal Companies and Renewable Energy Coalition sponsored the testimony of Donald Schoenbeck. He recommended that when QF developers execute a PPA, the QF could post either "a fixed $/kW amount or an amount based upon the difference between the contract revenue payments and forward power prices for a period of three years starting at the expected commercial operation date." Tr. at 881. Using this forward mark-to-market option, Mr. Schoenbeck suggested that the deposit be adjusted every calendar quarter "to ensure adequate security has been posted by the QF throughout the licensing and construction period." *Id.* at 882. With these adjustments, he indicated that his clients would accept the inclusion of liquidated damage provisions in all PPAs. *Id.*

E(1). The Partial Settlement

After the close of the technical hearing on August 9, 2012, the Commission scheduled a settlement conference to allow the parties to informally discuss standard PPA terms related to delay security and liquidated damages. Order No. 32617. The participating parties met in settlement conferences on August 23 and September 7, 2012. On October 2, 2012, a "Partial Settlement Stipulation" was filed on behalf of 13 of the 25 parties that participated in the settlement conference.[6] On October 16, 2012, the Commission issued a Notice of Partial Settlement and invited the parties and other interested persons to submit written comments regarding the partial settlement no later than October 25, 2012. Supporting comments were filed by Avista, Staff and one public witness. Idaho Power and C/E/S filed opposing comments.

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[6] The signing parties included: Rocky Mountain Power; Staff; Renewable Energy Coalition; Dynamis; North Side Canal; Twin Falls Canal; Birch Power, ICL; SRA; Idaho Wind Partners; Ridgeline; Big Wood Canal; and American Falls Reservoir District.

The signing parties agreed that existing PPAs that have been approved by the Commission shall not be affected by the settlement and that all new PPAs after the date of the Partial Settlement Stipulation conform to the terms contained in the settlement. Settlement at ¶¶ 9, 12. They also agreed that the settlement represents a compromise of the parties' position. They further assert that the settlement "is reasonable and in the public interest. They urged the Commission to adopt the Settlement Stipulation without condition or modification." Order No. 32665 at 1-2. The specific terms of the settlement are set out below:

1. Calculation of the Security Deposit. The parties agree that a security deposit or performance bond ("the Security Deposit") will be required for each new PURPA agreement (PPA) entered into after the date upon which the Commission adopts and approves this Settlement Stipulation. The purpose of the Security Deposit is to provide security for: (1) Delay Damages during the Cure Period if the QF is not in commercial operation by the Scheduled Commercial Operation Date set out in the PPA; and (2) Termination Damages if the QF cannot cure a failure to achieve commercial operation and a party seeks termination of the PPA. The Security Deposit shall be set at $45 per kilowatt (kW) of nameplate capacity for each new PPA. The cash or other liquid Security Deposit will be forwarded to the utility no later than thirty (30) days after the Commission issues its final Order approving the PPA.

2. Refund of Security Deposit. If the QF has achieved commercial operation in accordance with the Scheduled Commercial Operation Date set out in the PPA, the utility will promptly refund or rebate the Security Deposit to the QF.

3. Failure to Achieve Commercial Operation – Delay Damages. In the event the QF fails to achieve commercial operation by the Scheduled Commercial Operation Date contained in the PPA, Delay Damages shall be calculated based upon the difference between market rates at the time the QF fails to achieve its Scheduled Commercial Operation Date and the avoided cost rates contained in the PPA during the Cure Period. Delay Damages, if any, during the Cure Period will be drawn from the Security Deposit held by the utility. If the Security Deposit is insufficient to defray all of the Delay Damages, then the QF will promptly pay the outstanding Delay Damages. If the QF achieves commercial operation during the cure period, any remaining Security Deposit beyond the amount of any Delay Damages shall be refunded to the QF.

4. Cure Period. The defaulting party shall have one hundred twenty (120) days from the Scheduled Operation Date to cure its default.

5. Failure to Cure. In the event the QF fails to achieve commercial operation within the Cure Period, then the non-defaulting party may, at its option, collect its Delay Damages as calculated in Paragraph No. 3 above, terminate the Agreement, and calculate its Termination Damages, if any. If the QF fails to achieve commercial operation within the cure period and the non-defaulting party elects to terminate the Agreement, the Security Deposit may be used to: (a) first pay the Delay Damages arising during the cure period, if any; and (b) second pay Termination Damages, if any, arising after the Cure Period for the remaining term of the Agreement.

6. Termination Damages. The party claiming that the PPA is in default and seeking termination of the Agreement shall communicate its notice of default and claim for any Termination Damages to the other party within a reasonable time. The other party shall respond within fifteen (15) days. In the event of a dispute regarding the calculation of Termination Damages, either party may resort to a court of competent jurisdiction.

7. Undisputed Damages and Refunds. The utility may draw any undisputed Delay Damages or Termination Damages from the Security Deposit. In the event that the Security Deposit is insufficient to pay the undisputed damages, such undisputed damages will be paid promptly by the defaulting party. If the Security Deposit exceeds the total amount claimed as Delay Damages or Termination Damages, the utility shall promptly refund any portion of the deposit that is in excess of the claimed Delay Damages or Termination Damages.

8. Security Deposit for Existing QF Projects. The parties agree that a Security Deposit shall not be required in situations where the parties are entering into a new PPA for an existing QF project already in commercial operation so long as the new PPA is between the same parties and there are no material changes or modifications to the existing QF project.

E(2). Comments on the Partial Settlement

1. Avista. Although Avista did not sign the partial settlement, it supports the terms of the settlement. Comments at 3. Consistent with the partial settlement, Avista recommends that PPAs require "at a minimum, that QFs post a security equal to $45 per kilowatt based on installed capacity. In the event the QF failed to achieve commercial operation by the scheduled operation date, damages would be calculated based upon the difference between the market price of replacement power and the PPA price during a reasonable cure period. . . ." *Id.* at 2-3. Avista proposes that if the QF fails to achieve commercial operation by the end of the cure period, then

the "QF would forfeit its security [deposit] as liquidated damages and the utility could terminate the PPA." *Id.* at 3. In particular, Avista supports adoption of standard terms such as: (1) posting a security deposit of $45 per kW based on nameplate capacity; (2) a uniform cure period; and (3) calculating delayed damages incurred by the utility during the cure period based upon the difference between the PPA and market rates. Adopting the standard PPA terms will enhance the PPA process "by resolving issues between the utilities and QF developer[s]." *Id.*

2. Commission Staff. Staff also supports the partial settlement and urges the Commission to adopt it without material condition or modification. Staff Comments at 6. Staff notes that security deposits have been included in nearly all PURPA agreements signed since 2009 and that the $45 per kW deposit amount for nameplate capacity has been included in contracts since January 2010. *Id.* at 3. Staff states that the security deposit "helps ensure that the QF will perform and that funds will be available to cover damages should they arise. [I]f commercial operation is achieved per [the terms of] the PPA, the deposit is to be returned to the QF." *Id.* at 2. Staff explains that the security deposit can be used to either pay delay damages during the standardized 120-day cure period if the QF is not commercial operation, or termination damages if the QF cannot achieve commercial operation during the cure period and a party seeks termination of the PPA. *Id.* Staff also observes that under the terms of the settlement, the security deposit is to be forwarded to the utility no later than 30 days after the Commission issues its final Order approving the PPA.

Staff asserts that the security deposit is essential to adequately protect the utility and its ratepayers from default by a QF. The $45 per kW is a reasonable deposit amount that would likely cover most, if not all delay and/or termination damages. *Id.* at 3. Staff also recommends approval of the standardized term that requires the prompt refund of the security deposit to the QF if it achieves commercial operation in accordance with the PPA. If "there is a delay and a cure within the [120-day] cure period, the undisputed portion of the deposit will be returned to the QF." *Id.* In other words, the security deposit is only maintained for as long as necessary. *Id.*

Staff recognizes that determination of the exact amount of delay damages has frequently led to disputes between a QF and a utility. "The partial settlement will help to alleviate disputes by specifying [that] . . . delay damages shall be calculated based upon the difference between market rates at the time the QF fails to achieve its scheduled commercial operation date and the avoided cost rates contained in the PPA during the cure period." *Id.* at 3-

4. Basing delay damages on the difference between the market rates and the contract rates "fairly assesses the amount of the damages and holds the QF responsible for the full amount of actual damages without imposing a penalty." *Id.* at 4. Staff also supports the settlement because if the security deposit is insufficient to defray the delay damages, the QF will promptly pay the outstanding delay damages. Conversely, if the QF achieves commercial operation during the cure period, then any undisputed security deposit beyond the amount of any delay damages shall be refunded to the QF. *Id.*

Staff observes that if the PPA is terminated because the QF fails to achieve its commercial operation, then damages may extend beyond the cure period. Per the settlement, then deposits may be used to: (a) first pay delay damages arising during the cure period, if any; and (b) second pay termination damages, if any, arising after the cure period for the remaining term of the PPA. Settlement at ¶ 5. In the event the parties are unable to agree to termination damages, if any, then any party may bring suit in a court of competent jurisdiction. Because termination damages "are exceedingly difficult to quantify in advance, and because they depend on the circumstances of each individual case, Staff believes it is appropriate to leave determination of the [termination] damages to negotiation[s] between the parties or to a court if there is a dispute." Comments at 4.

Finally, Staff notes that calculating delay damages based on actual damages eliminates an argument that the previous liquidated damages (now [the] security deposit) were punitive and unreasonable." *Id.* at 5. Based on its review of the partial settlement, Staff determined that its terms are just and reasonable and in the public interest. Consequently, Staff recommends that the Commission approve and adopt the partial settlement. *Id.* at 6.

3. <u>Opposing Comments</u>. Idaho Power indicates that there was "little to no value in entering into some kind of compromise of its position[s] that it has set forth . . . in this proceeding" without complete agreement from all the QF parties. Comments at 1. It urges the Commission to continue the current requirements of requiring QFs post delay damage security calculated at $45 per kW of nameplate capacity. *Id.* at 3, 5. The utility argues that the damages provisions of the partial settlement do not "adequately compensate customers for the risks assumed by customers and the damages incurred by a QF breach." *Id.* at 2. Idaho Power continues to argue that a QF may choose or not choose to bring its project into commercial operation. Thus, "a QF has the ability to eliminate its own downside [risk], to the direct and

substantial harm and detriment of Idaho Power's customers, and take advantage of the upside" if prices are more favorable to the QF. *Id.* at 5.

C/E/S filed joint comments opposing the partial settlement. They disclose that they did not sign the partial settlement "because it simply codifies the status quo. The only true settlement issue that was resolved was the unremarkable and obvious concession that existing projects will not be required to post a delayed security deposit." Joint Comments at 1. C/E/S reiterates its position at the hearing by attaching Dr. Reading's testimony as comments.

Commission Findings

Based on our review of the underlying testimony, the partial settlement, and the comments filed in response to the settlement, we find that the partial settlement represents a fair, just and reasonable resolution to the issue of liquidated damages. Contrary to the assertion made by C/E/S, the partial settlement does not simply codify the status quo. In our view, the settlement represents a reasoned approach to the issues of risks and damages in the event a QF fails to perform under the terms of its PPA. We find that the requirement that a security deposit be posted 30 days after the Commission approves the PPA is reasonable. We further find it reasonable to base delay damages on the actual difference between the PPA rates and the market rates. This is similar to the recommendation offered by Mr. Schoenbeck and is in agreement with Dr. Reading's testimony that delay damages should be based on damages measuring the "difference between the rate . . . in the QF contract and the actual cost for replacement power. . . ." Tr. at 961.

As we previously observed in Order No. 31034, posting adequate security "acts not only as an incentive for PURPA project owners to complete their projects on time, but it can also mitigate any additional costs which might arise when a utility is forced to purchase substitute power on the open market." Order No. 31034 at 3; Exh. 519. However, we also noted that such security "'should not be punitive' and 'should constitute a fair and reasonable offset of a regulated utility's estimated increase in power supply costs attributable to the PURPA supplier's failure to meet its contractually scheduled operation date.' Order No. 30608." *Id.* at 4.

Although C/E/S argued that the $45 per kW amount was unreasonable, we are not persuaded for several reasons. First, as indicated in the partial settlement, a broad array of parties agreed that $45 per kW is a reasonable amount for the security deposit. Second, a survey conducted by Avista regarding the $45 kW amount showed that the utilities charged a comparable amount "and actually substantially higher in some cases." Tr. at 164; Exh. 519, Order No. 31034 at 3 (in a survey of 10 utilities only 1 required "less than $25 per kW, while the other 9 utilities required security of at least $50 per kW."). Third, the Commission has previously found that an increase in the delay security amount to $45 was "reasonable and necessary." Exh. 519, Order No. 31034 at 3. Fourth, it is reasonable to set a uniform amount so that all parties to a PPA know how the security deposit is to be calculated and can calculate the amount of the deposit before executing the contract. Finally, the $45 per kW deposit is balanced with the fact that the deposit is returned if the QF meets its scheduled operation date or becomes operational during the cure period and the undisputed amount is returned to the QF.

As set out in the partial settlement that we adopt, the security deposit is to be used as a source of actual damages for both delay damages (the inability of the QF to bring its facility on-line during the 120-day cure period) and also as a source of termination damages in the event the PPA is terminated. If there is a dispute among the parties regarding the calculation of termination damages, then either party may take their dispute to a court of competent jurisdiction. Of course, in the event the QF comes on-line as scheduled, then "the utility will promptly refund the Security Deposit to the QF" developer. Partial Settlement at ¶ 2.

Consequently, we find that the standard terms proposed in the partial settlement are fair, just and reasonable, and in the public interest. Moreover, we find that the $45 per kW of installed capacity is a reasonable amount to post as a security deposit/performance bond. Thus, we approve and adopt the partial settlement for all new PPAs entered into after the date of this Order.

F. Curtailment

Idaho Power proposed that the Commission approve a new tariff – Schedule 74 (Curtailment). Schedule 74 would allow Idaho Power, during low loading periods, "to meet its energy needs by using its own lowest cost, base load resources instead of dispatching less efficient, higher cost resources to accommodate PURPA generators on the Company's system." Tr. at 615.

1. Utilities. Idaho Power argues that its proposed tariff is consistent with PURPA and FERC rules. *Id.* The Company contends that 18 C.F.R. § 292.304(f) allows a utility to curtail higher cost QF energy if the utility would have to dispatch less efficient, higher cost units to meet system load. *Id.* The Company maintains that intermittent PURPA generation

frequently provides energy at night and during the spring and fall months. These times coincide with Idaho Power's low load periods. *Id.* at 617. During these low loading periods, Idaho Power generates and/or must accept more energy than its customers need and must sell excess power back into the market – sometimes at a loss.

Idaho Power explains that the addition of large amounts of intermittent generation on the system, coupled with the fact that intermittent generation often generates when the Company's system load is at a low level, "forces the Company to use the flexibility of the hydro system that is normally used to meet load swings and to meet system balancing needs . . . of the wind generators. Thus, the Company is forced to use base load generation resources to integrate the intermittent QF generation which comes at an additional cost to customers." Tr. at 610. Proposed Schedule 74 would allow Idaho Power to curtail its QF generation if, during low load situations, Idaho Power would otherwise be forced to utilize less efficient, higher cost units to meet impending load following a low loading period.

2. Commission Staff. Staff supports the approval of Idaho Power's proposed Schedule 74. Staff maintains that existing Schedule 72 gives Idaho Power the authority to curtail and the proposed Schedule 74 outlines the policies and procedures for curtailment. *Id.* at 1113. Staff states that Schedule 74 would allow Idaho Power to curtail for system efficiency and economics under limited circumstances – reasons not allowed under Schedule 72. *Id.* Staff argues that Idaho Power's proposed Schedule 74 is consistent with PURPA and FERC regulations.

3. Intervenors. The Canal Companies oppose Idaho Power's proposed Schedule 74. Tr. at 874. The Canal Companies argue that Idaho Power's proposal unilaterally modifies existing contracts. The Companies maintain that existing Idaho Power PPAs do not contain language to allow for operational or economic curtailment. Thus, implementing Schedule 74 would unilaterally change existing contracts that were mutually negotiated by the parties. *Id.* at 876.

The Canal Companies further argue that Idaho Power presents a misleading picture of FERC's rulings regarding operational curtailment rights. The Canal Companies assert that, "[b]y employing production simulation models such as AURORA, the economic dispatch of the system, including during light load hours, has already been taken into account in deriving the avoided cost prices." *Id.* at 878. Therefore, the Canal Companies maintain that the utility has already accounted for light load periods and should not be permitted to also curtail a QFs production.

Finally, the Canal Companies state that Langley Gulch is mischaracterized by Idaho Power as a must-run base load resource. Tr. at 879. They argue that Langley Gulch's ramp rate does not qualify it as a must-run base load resource. They further maintain that Idaho Power has not shown that FERC's low load scenario exists on Idaho Power's system. *Id.* The Canal Companies suggest other options for light-load conditions such as selling power to surrounding service territories in order to avoid curtailment. The Canal Companies characterize Idaho Power's proposed Schedule 74 as a "poorly disguised effort to impose economic curtailment on QF deliveries." *Id.*

C/E/S also opposes Idaho Power's proposed Schedule 74. C/E/S maintains that Schedule 74 amounts to economic curtailment not permitted by FERC's regulations. Tr. at 971. C/E/S further asserts that Idaho Power already possesses the authority to curtail for operational concerns under its existing Schedule 72. C/E/S maintains that Idaho Power's proposal primarily takes issue with the burden of intermittent resources, i.e., wind. C/E/S argues that the Idaho Commission has already approved and implemented a wind integration charge in order to address the intermittency of the resource and integration challenges that wind presents. *Id.* at 972. C/E/S argues that Idaho Power has not adequately demonstrated that its system configuration is similar to that contemplated by FERC within 18 C.F.R. § 292.304(f). *Id.* at 975.

Idaho Wind Partners maintains that curtailment under Section 304(f) does not apply to pre-determined, fixed price contracts. *Id.* at 815. Idaho Wind Partners argues that fixed price contracts already take into account "the anticipated average or composite avoided costs for the life of the contract, including the potential for negative avoided costs." *Id.* Therefore, Idaho Wind Partners opposes the application of Idaho Power's proposed Schedule 74 to existing, fixed price contracts.

Commission Findings

First, this Commission has thoroughly reviewed 18 C.F.R. § 292.304(f) and its subsequent interpretations. We find that Section 292.304(f) clearly allows for curtailment of QF power under specific circumstances when base load resources would be forced to cut back to a point where they might not be able to increase their output rapidly enough to meet subsequent system demand. 45 Fed.Reg. 12214 at 12227 (February 25, 1989) (FERC Order No. 69).

During certain low load conditions, a utility is permitted to curtail QF power so that base load resources do not fall below a must-run level.

We further find that, while each power purchase agreement (PPA) that we have reviewed contains a general reference to 18 C.F.R. § 292.304(f), curtailment under this section was not reasonably contemplated when the parties entered into their agreements. The apparent need for such authority to curtail under these circumstances has only presented itself within the last several years in Idaho – and, as evidenced by the testimony, seems to be a problem only on Idaho Power's system.

We acknowledge that Idaho Power has had to accept what it considers a glut of QF power. This Commission, through these proceedings, is attempting to provide Idaho Power and the other Commission-regulated utilities with the tools necessary to manage QF power without harming ratepayers. However, we find that Idaho Power has not provided sufficient information or persuaded us about its must-run resources, the frequency of such conditions, and the transparency of its proposed schedule for us to approve Schedule 74.

It became apparent at hearing that Idaho Power's proposed curtailment tariff lacks sufficient definition and is void of some provisions altogether. As proposed, Schedule 74 does not provide for a penalty to Idaho Power or compensation to a QF if the QF is curtailed without proper notice. Tr. at 670. The proposed tariff does not address consequences and/or compensation to a QF if curtailment by the utility would cause the QF not to meet its firming provisions required by contract (i.e. 85% mechanical availability guarantee or 90% threshold in a 90/110 contract). *Id.* As proposed, the tariff has no limit on the number of hours or days that could be declared must-run periods. *Id.* at 694. As written, Schedule 74 does not provide for notice to the Commission or a QF that the utility has declared a must-run period or its expected duration. *Id.* at 696. In addition, proposed Schedule 74 does not provide for an opportunity for the Commission or a QF to contest the utility's declaration of a must-run period. *Id.* Finally, it is unclear whether Schedule 74 would operate to curtail Idaho Power's own PURPA resources. *Id.* at 677.

We find that, as proposed, Idaho Power's Schedule 74 is too vague and adoption of such a tariff is not adequately supported by the evidence provided in this proceeding. If the Company believes that the over-supply of QF power presents operational problems during light-load periods then it should address this issue when it negotiates new PPAs.

G. Ownership of Renewable Energy Certificates (RECs)

We next turn to the dispute regarding renewable energy credits (RECs). Typically RECs (also known as environmental attributes, green tags, or renewable trading certificates) represent the environmental attributes associated with 1 MWh of electricity generated from an eligible renewable energy source. Order No. 32580 at 4. The utilities and Staff generally assert that RECs should belong to the utility. Conversely, the PURPA or QF developers argue that RECs should belong to them. Before providing the position of the parties in greater detail, it is helpful to review the history, legal background, and the interplay between RECs and PURPA. In June 2012, the Commission addressed the history and interplay between RECs and PURPA. *See* Order No. 32580.[7]

1. Background. A renewable portfolio standard (RPS) typically requires electric utilities to generate or purchase a certain percentage of their annual generation (their "portfolio") from designated renewable energy sources or meet their RPS obligation by the purchase of unbundled RECs. Since about 1995, about 25 States and the District of Columbia have created mandatory RPS programs. There is no federal RPS standard. Order No. 32580 at 3, *citing Steven Ferrey, et al.* "Fire and Ice: World Renewable Energy and Carbon Control Mechanisms Confront Constitutional Barriers," 20 Duke Envtl. L. & Pol'y F. 125 at 146 (2010) (*hereinafter "Ferrey"*). The purpose of adopting RPS programs is to improve air and water quality, reduce greenhouse emissions, broaden fuel diversity, enhance energy security, and hedge against the price volatility of fossil fuels. Order No. 32580 *citing American Ref-Fuel Company*, 105 FERC 61,004 at ¶ 4 (Oct. 1, 2003) *rehr'g. denied*, 107 FERC 61,016 (April 15, 2004), *dismissed sub nom. for lack of jurisdiction, Xcel Energy Services v. FERC*, 407 F.3d 1242 (D.C.Cir. 2005). RECs did not exist and were not contemplated when PURPA was enacted in 1978. *American Ref-Fuel*, 105 FERC at ¶ 4; Order No. 29480 at 3. Indeed, PURPA and RPS programs were created for different reasons.

"About half of the states that have adopted RPS programs allow utilities to use [RECs] to meet their RPS requirements." Order No. 32580 at 4 *citing Ferrey* at 145. As the Second Circuit explained in *Wheelabrator Lisbon v. Connecticut Dept. Public Utility Control*,

[7] Several parties in this case have cited to Order No. 32580 in their legal briefs or testimony addressing RECs. Parties addressing Order No. 32580 include: Idaho Power, C/E/S, ICL, Idaho Wind Partners, and Staff.

> RECs are "tradable certificates . . . that correspond to a certain amount of renewable energy generated by a third party." *American Ref-Fuel*, 105 FERC at ¶ 61,005. Generally speaking, RECs are inventions of state property law whereby the renewable energy attributes are "unbundled" from the energy itself and sold separately. The credits can be purchased by companies and individuals to offset use of energy generated from traditional fossil fuel resources or . . . to satisfy certain requirements that [utilities] purchase a certain percentage of their energy from renewable resources.

531 F.3d 183, 186 (2d Cir. 2008) (emphasis added); Order No. 32580 at 4. FERC has declared that RECs "exist outside the confines of PURPA. PURPA thus does not address the ownership of RECs. . . . 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." Order No. 32580 at 5 *quoting American Ref-Fuel*, 105 FERC at ¶ 23; Order No. 29480; *Idaho Wind Partners*, 136 FERC 61,174 at n.10 (Sept. 15, 2011) ("the sale and trading of RECs are for the states to decide"). Because "RECs are state-created, different states can treat RECs differently." *American Ref-Fuel*, 107 FERC 61,016 at n.4.

The parties in this case agree that the Idaho Legislature has not implemented an RPS program nor has it enacted any statute which addresses the ownership of RECs. Moreover, this Commission has noted on several occasions, the "State of Idaho has not created a REC program, has not established a trading market for [RECs] nor does it require a renewable resource portfolio standard." Order No. 32580 at 9 *citing* Order Nos. 29480, 29577, 29630. With this background, we now turn to the arguments of the parties.

2. Utilities. Rocky Mountain believes that RECs should belong to the utility whenever the QF sells energy to the utility under PURPA. Tr. at 222. Company witness Paul Clements explains but for PURPA's must purchase provision, utilities would not be required to purchase the renewable energy.

> Without these [renewable or efficiency] characteristics, the [QF] would not be able to require the utility to purchase its energy at all. In other words, it is only by virtue of the existence of the Environmental Attributes that facilities are deemed QFs and utilities become obligated to purchase their power. In the case of eligible renewable energy resource QFs, these Environmental Attributes are the essence of the requirements to purchase the output, and is therefore part of what the utility is buying with the payment of avoided costs. If Rocky Mountain Power does not get the QF Environmental Attribute, it is not receiving the very characteristic that enabled the facility to achieve its QF

status, and which thereby triggers the utility's obligation to purchase the output from the facility.

Tr. at 223-24 (emphasis added). If ownership of the RECs is not assigned to the utility, then "Rocky Mountain Power and its customers would in effect be paying twice for that attribute . . . ." Tr. at 223.

Mr. Clements maintains that the subsequent unbundling between the PURPA power and the RECs associated with that very same power does not justify separate compensation. Tr. at 224. As originally envisioned by PURPA, a purchasing utility is not buying "undifferentiated energy from the Grid; it is buying energy that . . . the utility is required by law to purchase." Tr. at 225. The subsequent creation of RECs with their associated market value should not deprive utilities of the attributes subsumed in the renewable power they are required to purchase under PURPA. He recommended that any power purchase from a QF should assign the associated environmental attributes to the purchasing utility.

In its brief, Avista first argues that the Commission has jurisdiction to determine the ownership of RECs. Avista insists that FERC has expressly disclaimed jurisdiction over RECs and has held that the states "have the power to determine who owns the RECs in the initial instance, and how they may be sold or traded." *American Ref-Fuel*, 105 FERC 61,004 at ¶ 23. Avista asserts that the Public Utilities Laws (61-501, 61-503, 61-507, etc.) give the Commission subject matter jurisdiction over the determination of RECs. More specifically, Avista maintains that a QF may be considered a "public utility" as defined by *Idaho Code* § 61-129. Although it recognized that PURPA prohibits states from regulating QFs in the same manner as other public utilities, Avista nevertheless argues that federal law "does not prohibit all regulation of QFs by states." Avista Brief at 4, n.15 *citing* 18 C.F.R. § 292.602(c)(2); *Independent Power Producers of New York*, 80 FERC 61,125 (1997)(affirming the requirement that QFs must comply with certain state monitoring requirements was a legitimate exercise of the state's authority). Avista also states that the avoided cost rate cannot be adjusted to compensate for RECs. *Id.* at 6.

Avista asserts that other state commissions have addressed the ownership of RECs. Brief at 5 *citing In Re the Riley Energy Corp.*, 2004 WL 3160409 (Conn. DPUC 2004). In particular, Avista insists that the State Commissions of Connecticut, Nevada, New Jersey, North Dakota, Oregon, Pennsylvania, Utah, and Colorado have all determined that REC ownership should be vested in the utility. *Id.* at 5, n.16.

Idaho Power asserts in its brief that it is "well established that the question of REC ownership is properly decided by the states. PURPA does not govern the question [of RECs]." Brief at 69, *citing American Ref-Fuel*, 105 FERC at ¶ 23, *rehr'g denied*, 107 FERC 61,016 (2004), *appeal dismissed sub nom.*, *Xcel Energy Services v. FERC*, 407 F.3d 1242 (D.C. Cir. 2005); *Wheelabrator Lisbon v. Connecticut Dept. of Util. Control*, 531 F.3d 183, 190 (2d Cir. 2008); IPUC Order No. 32580. The Company further argues that the Commission has the subject matter jurisdiction to decide the REC issue. Brief at 73-79. Like Avista, Idaho Power maintains that the Commission's organic statutes (§§ 61-502, 61-503, 61-506, 61-507 and others) grant the Commission broad powers to regulate the terms and conditions of PURPA contracts. *Id.* at 77-78.

Idaho Power points to decisions of other state commission (Connecticut, New Jersey, Maine, Pennsylvania, Wyoming) that do not have REC or RPS statutes. *Id.* at 80. The utility argues these other state cases represent a compelling argument why RECs should belong to the purchasing utility. "Simply put, in the absence of an Idaho RPS [or REC] 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." *Id.* at 86.

Idaho Power also mentions a November 2011 order issued by the Wyoming Public Service Commission. In Order No. 12750, the Wyoming Commission found that Rocky Mountain Power's argument that the utility should retain the RECs was persuasive. Relying on Mr. Clements testimony, the Wyoming Commission found that Rocky Mountain

> 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 had in the past made it clear that REC revenues are a key component to mitigate, to an extent, the effects on customers of the ongoing series of rate increases filed 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.

Idaho Power Brief at 86-87, *citing* Wyoming Order No. 12750 at ¶ 63 (Nov. 4, 2011).

3. Commission Staff. Staff also insists that the Commission has the subject matter jurisdiction to decide the REC issue. In particular, Staff notes that the Legislature has delegated authority to the Commission "to deal broadly with existing and future rates, rate schedules and contracts affecting rates." *Washington Water Power Co. v. Kootenai Environmental Alliance*, 99 Idaho 875, 880, 951 P.2d 122, 127 (1979); Staff Brief at 4. Staff maintains that the Commission

has the authority to decide the REC issue because the ownership of RECs and their value are inextricably tied to power rates and contracts affecting rates. *Id.* Staff observed that the costs associated with QF contracts are directly recovered from ratepayers. *Id.* at 4.

Staff also asserts that but for the must purchase requirement of PURPA, the QF and the associated REC, would not exist. Echoing a point raised by Rocky Mountain, Staff states in its brief that if a

> QF restricts the renewable attributes prior to conveying the energy to a utility, then the bases for which the QF initially received its [qualifying] status and gained its authority to sell no longer exists. Said another way, if the utility is being compelled to purchase based on the energy being [classified as] renewable, then the renewable status should remain with the energy purchased by the utility. Moreover, <u>an environmental attribute is an intangible characteristic of the energy generated by a renewable energy facility</u>, not a characteristic of the facility itself.

Brief at 4 (emphasis added).

Staff notes that one of the purposes of PURPA was to reduce the country's dependence on fossil fuels by encouraging renewable technologies and cogeneration. However, one of the key underpinnings of PURPA was to make "ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged [QF] alternatives." *Id.* at 5 *quoting Southern Cal Edison, San Diego Gas & Electric*, 71 FERC 61,269, 62,080 (1995). Staff insists that Congress did not intend to create an environment in which renewable energy producers thrive to the detriment of the utility's ratepayers.

In balancing the competing REC arguments, Staff recognizes the differences in assigning RECs under the IRP and SAR methodologies. More specifically, "because the SAR is a [natural] gas-fired resource that does not produce RECs," [such] "RECs would be a unique attribute of the power provided by the QF." Tr. at 1122-23. Conversely, under the IRP Methodology, a utility's 20-year resource portfolio contains some renewable resources. In this latter case, the utility would presumably be entitled to RECs. *Id.*

4. <u>Intervenors</u>. Although Renewable Northwest (RNW) recognizes that RECs are "a creature of state law and exist outside of PURPA," it argues that assigning RECs to the utility would nevertheless violate PURPA by: (1) discriminating against QFs; (2) discouraging future QF development; and (3) represent a windfall to utilities. Brief at 5, 1-4. RNW argues that unbundled RECs are not part of the avoided cost methodology. *Id.* at 5-6. It also suggests that

neither the SAR nor the IRP methodologies used to calculate avoided costs in Idaho include compensation for RECs in any fashion. *Id.* at 7. Providing the RECs to utilities would mean that utilities would receive energy, capacity and RECs, but only pay for the energy and capacity. *Id.* at 9. Such a finding would run afoul of PURPA's anti-discrimination provision and undermine PURPA's objective to encourage renewable generation. *Id.*

The Canal Companies note that FERC recognizes that RECs, like the thermal output from cogeneration QFs, may be sold separately (i.e., unbundled) from the capacity and energy output of QFs. Brief at 9. FERC has emphatically stated that avoided cost rates are not intended to compensate the QF for more than capacity and energy. *Id.* at 10. More recently, FERC affirmed its holding in *American Ref-Fuel* that "the sale and trading of RECs are for the state to determine, and that this is not an issue that PURPA controls." *Idaho Wind Partners*, 136 FERC 61,174 at ¶ 10 (Sept. 15, 2011).

The Canal Companies and C/E/S both maintain that prior Order Nos. 29480 and 29577 of this Commission (in Case Nos. IPC-E-04-02 and IPC-E-04-16, respectively) declared that RECs do not belong to the utilities. Canal Brief at 10-11; C/E/S Brief at 29-30. Consequently, C/E/S argues that these Orders may be interpreted to hold that "Idaho QFs are the default owners of [RECs]." Brief at 30. Finally, if the Commission does assign RECs to utilities, then utilities must compensate the QFs for the "taking" of RECs. "QFs' interest in the transferable [and unbundled] RECs of QFs is a compensable property interest." Canal Brief at 16. Taking of a QF's REC property without just compensation would violate both the U.S. and Idaho Constitutions. *Id.*; C/E/S Brief at 32.

The Idaho Conservation League (ICL) maintains that the Commission has no authority to resolve REC ownership. Brief at 3. ICL notes that the Commission in its prior REC Order No. 32580 explained that "RECs are inventions of state property law whereby the renewable energy attributes are 'unbundled' from the energy itself and sold separately." *Id.* at 3-4, *citing* Order No. 32580 at 4. Absent a specific Idaho statute that addresses RECs, ICL maintains that the legal status of RECs depends upon "traditional notions of common law, which in Idaho vests those rights in the owner who expends the time and effort to create the property." *Id.* at 4 *citing King v. Chamberlain*, 20 Idaho 504, 118 P. 1099 (1911). "Because QF developers expend their own time and resources to create an independent property right in RECs, . . . QF developers inherently own RECs under Idaho law." Brief at 4.

Dynamis and Renewable Energy Coalition (RE) also argue that the Commission has no authority to determine the ownership of RECs. Relying upon the *Kootenai Environmental Alliance* case, they assert there is no statute that gives the Commission the authority to adjudicate the ownership of RECs. REC ownership does not fall into those subject matter areas that the Commission traditionally regulates, nor does it require the application of the Commission's technical expertise. Brief at 3-4, *citing Kootenai*, 99 Idaho 875, 882, 591 P.2d 122, 129 (1979). They also note that the 2012 Legislature did not pass Senate Bill No. 1364 which, if enacted into law, would have recognized that RECs associated with QF power sales are "attributes of the power purchased by the utility." Brief at 6; Exh. No. 802. Although, no legislative hearings were held on the bill, they infer that the printing of this bill reinforces the view that the Commission does not have authority to adjudicate RECs. *Id.*

Commission Findings

1. Jurisdiction. We turn first to the issue of subject matter jurisdiction. Dynamis/RE and ICL argue that the Commission does not have jurisdiction to decide the REC issue. First, ICL argues that because there is no REC statute, the Commission cannot decide the matter. Second, they argue that the Legislature "has considered but ultimately rejected two attempts at addressing the ownership of RECs." ICL Brief at 2; *see also* Dynamis/RE Brief at 5-6; Exh. 802, 803. Dynamis/RE argue that the failure of the Legislature to pass a REC statute should be construed as the Commission lacking authority to decide the REC issue. Conversely, Avista, Idaho Power and Staff argue that the Commission does have the requisite subject matter jurisdiction to decide the REC ownership dispute.

At the outset, we recognize that the Commission is a creature of statute and our jurisdiction is dependent upon our statutory authority. The Commission exercises limited jurisdiction based upon the authority given by the Legislature. *Washington Water Power v. Kootenai Environmental Alliance*, 99 Idaho 875, 879, 591 P.2d 122, 126 (1979). Our Supreme Court has noted that the Commission may determine whether we have jurisdiction over specific issues. *Id.* However, "once jurisdiction is clear, the Commission is allowed all power that is either expressly granted by statute or which may be fairly implied" to effectuate its purpose. *Idaho State Homebuilders v. Washington Water Power*, 107 Idaho 415, 418, 690 P.2d 350, 353 (1984); *Id.* We do not agree with ICL and Dynamis/RE that the Commission does not have authority to determine the REC question for several reasons.

First, it is well settled that the Commission has been granted authority to review QF contracts and resolve disputes between QFs and electric utilities. *A. W. Brown v. Idaho Power*, 121 Idaho 812, 816, 828 P.2d 841, 845 (1992); *Empire Lumber Co. v. Washington Water Power*, 114 Idaho 191, 755 P.2d 1229 (1988); *Afton Energy v. Idaho Power Company* 107 Idaho 781, 693 P.2d 427 (1984); *Idaho Code* § 61-612. The disposition of RECs is now a term that is found in most, if not all, PURPA contracts. Since 1980, the Commission's PURPA procedures have required that all QF contracts be submitted to the Commission for its approval. Order No. 15746, 38 P.U.R. 4th 352 (Idaho 1980); Order No. 29632, 2004 WL 2724113 (Idaho PUC); *see Rosebud Enterprises v. Idaho PUC*, 128 Idaho 609, 620, 917 P.2d 766, 778 (1996). Likewise, *Idaho Code* § 61-502 authorizes the Commission to review contracts with utilities that affect utility rates and charges. Moreover, *Idaho Code* § 61-503 provides that the Commission shall have the power to investigate the contracts of any public utility.

Second, in *A.W. Brown*, our Supreme Court rejected the QF's argument that the Commission has no jurisdiction "to litigate the common law contract issues between [the QF] and Idaho Power. . . ." 121 Idaho at 819, 828 P.2d at 848. The Court rejected that argument and found "that the Commission 'has jurisdiction to hear complaints against utilities alleging violation of any provision of law. . . .'" *Id.* In *Empire Lumber*, the Court found that the Commission has been "granted authority by the Idaho statutes to, and is the appropriate forum to resolve" PURPA contract issues. 114 Idaho at 192, 755 P.2d at 1230. In this proceeding, the parties have argued about the ownership of RECs in standard PURPA contracts and this dispute is ripe for decision.

Third, we find that the disposition of RECs directly affects rates. As noted above, the sale of RECs directly offsets the rates that utilities must pay QFs for power. The cost of purchasing QF power is initially recovered in the annual Power Cost Adjustment (PCA) mechanisms for Idaho Power and Avista, and in the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain. Tr. at 392, 1107. Upon the utility's next general rate case filing, QF costs become part of base rates. The sale of RECs by utilities is recorded in the PCA/ECAM mechanisms of the utilities. Tr. at 573, 1192, 1193-94. Thus, the disposition of RECs directly affects utility rates. And, as our Supreme Court noted in *Kootenai*, *Idaho Code* §§ 61-502 and 61-503 embody "the legislative grant of authority to the Commission to deal broadly with existing and future rates, rate schedules and contracts affecting rates." 99 Idaho at 880, 591 P.2d at 127. Consequently, we find that the Commission has subject matter jurisdiction to decide the REC issue.

Finally, we find Dynamis/RE's argument that the Commission lacks authority to decide the REC issue based on the introduction of a REC bill (SB 1364) in the last legislative session to be unpersuasive. Dynamis/RE acknowledges there were no hearings on the bill. Brief at 6. The fact that legislation was introduced but no hearings were held, no committee votes were taken, and the Legislature as a whole did not vote on the bill is accorded little weight. *See Casey v. Com'er of Labor & Ind.*, 167 A.2d 900 (N.J.Super. 1961). As any observer of the legislative process recognizes, many more bills are introduced than enacted, and it is not unusual for bills in Idaho to be "printed" (i.e., assigned a bill number), and receive no further legislative consideration.[8]

2. <u>RECs</u>. We now turn to the merits of the REC issue. Despite the disagreement among the parties regarding RECs, there are several facts which are not in dispute. First, all the parties agree that PURPA does not control RECs – RECs are controlled by the state. RECs exist outside the confines of PURPA. Second, there is no Idaho law that implements a renewable portfolio standard (RPS) program or addresses the ownership of RECs. Order No. 32580, 29480 at 9. Third, the parties agree that Idaho's avoided cost rates do not compensate QFs for RECs. Moreover, this Commission has previously found, avoided cost rates "are not intended to compensate the QF for [RECs]." Order No. 32580 at 8 *quoting Morgantown Energy Associates*, 139 FERC 61,066 at ¶ 47 (April 24, 2012). *See also California PUC*, 133 FERC 61,059 at ¶ 31 n.62 (Oct. 21, 2010).

As we noted in Order No. 32580, RECs resemble intangible assets. But for the "must purchase" provision of PURPA, RECs would not exist or be created for a PURPA project. RECs are non-physical assets which exist only in connection with something else, i.e., the purchase of

[8] Dynamis/RE's reliance on two other Idaho Supreme Court cases is also misplaced. Brief at 3-5. In *Alpert v. Boise Water Corp.*, 118 Idaho 136, 795 P.2d 298 (1990) the issue before the Court was the validity of franchise agreements between utilities and certain cities under *Idaho Code* §§ 50-329 and 50-329A. Here RECs are an integral part of PURPA contracts. The Court has observed many times that it is well settled that the Commission has been granted authority to review QF contracts and resolve disputes between QFs and electric utilities. In *Ada County Highway District v. Idaho PUC*, 151 Idaho 2, 253 P.3d 675 (2011), Dynamis/RE asserts that the Commission in that case argued that it had "statutory authority to order relocation of utility facilities owned by third-party beneficiaries." Brief at 5. That was neither the position of the Commission nor do third parties "own" utility facilities.

QF power under PURPA.[9] Order No. 32580 at 10, *citing* Black's Law Dictionary at 808 (6th ed. 1990). There is no REC without the QF generating power.

Having considered the positions advanced by the parties, we find that it is reasonable to apportion RECs based upon the SAR or IRP methodologies applicable to each QF project. The avoided cost rate paid to a QF under the SAR Methodology is based on a gas-fired surrogate resource. If the utility were not "avoiding" the cost by accepting the QF energy, it would build a gas resource. Gas resources do not produce RECs. Because the SAR Methodology is based upon a gas-fired surrogate and such a resource produces no RECs, we find that it is reasonable and appropriate to assign the RECs for SAR-based QFs to the QFs. Conversely, IRP rates are derived from the utility's actual resource portfolio. The IRP Methodology considers a utility's resource stack that contains both renewable and non-renewable resources. The rates are based on the actual generation characteristics of the renewable resource. Renewable resources, whether utility or QF owned, produce RECs. In this case, absent an agreement between the parties to do otherwise, we find it reasonable to equally apportion RECs between the utility and the QF. Tr. at 1122-23. Because both the utility and the QF are contractually and inextricably joined in the production, sale and purchase of QF power, we find that it is reasonable to apportion the unbundled REC assets in this manner. Under the IRP Methodology, we find that splitting RECs either 50%-50% each year over the life of the PPA, or equally in terms of years over the length of the contract, is reasonable. Indeed, several recent Orders have approved the splitting of RECs in this manner. *See* Order Nos. 32419 (Cedar Creek), 32451 (Riverside), 32384 (Interconnect Solar), 32294 (Clark Canyon), and 32125 (Rockland).

Assigning RECs to both the QFs and utilities (including their ratepayers) reasonably allocates the benefits and burdens from these unbundled REC assets. Typically unbundled RECs produced in Idaho are sold to produce revenue. From the utility's perspective, selling RECs produces revenue which directly offsets the utility's (and ratepayers) costs of purchasing power from QFs. Tr. at 573, 1192, 1193-94; *see* Order No. 32002. Thus, another tangible ratemaking element to RECs.

We further find that assigning RECs to the QFs under the SAR Methodology and splitting RECs under the IRP Methodology is also in the public interest. From the QF's perspective, revenues from the sale of RECs continue to provide a revenue stream to QF

[9] We recognize that RECs may exist in non-PURPA renewable projects. Order No. 32580 at n.5.

developers to encourage the development of renewable generation. This promotes the underlying purpose of PURPA and specifically recognizes that the SAR Methodology is based on a natural gas-fired surrogate. E.g., *Rosebud*, 128 Idaho at 627, 917 P.2d at 784. Splitting RECs under the IRP Methodology for wind/solar QFs larger than 100 kW and other QFs larger than 10 MW also mitigates those arguments that assigning RECs to either the QF or the utility in their entirety represents a revenue windfall to the recipient. Under the IRP Methodology, both the QF and the utility (including its ratepayers) share the benefits of selling RECs. Finally, because the ownership of RECs is apportioned as set out above, there is no taking of the intangible asset resulting from the QF-utility relationship. As the Connecticut Supreme Court found in a similar case, the "[PUC's] decision [to award RECs to the utility] could not constitute an unconstitutional taking under the State's Constitution because no property owned by the [QF] has been taken." *Wheelabrator Lisbon v. Dept. of Public Util. Control*, 283 Conn. 672, 700, 931 A.2d 159, 177 (2007); *Wheelabrator Lisbon*, 526 F.Supp.2d 295, 307 (D.Conn. 2006), *aff'med*, 531 F.3d 183 (2d Cir. 2008).

We are also not persuaded by the Canal Companies' and C/E/S's argument that two prior Commission Orders (Nos. 29480 and 29577) assigned RECs to the QF. As we found in our Order No. 32580, the Commission in Order No. 29480 did not reach the issue of REC ownership in Case No. IPC-E-04-02. We dismissed Idaho Power's petition for a "right of first refusal" because the petition did not "present an actual or judiciable controversy in Idaho and is not ripe for a declaratory judgment by this Commission." Order No. 29480. In the second Order relied upon by the Canal Companies and C/E/S (No. 29577), Idaho Power waived any claim to ownership associated with a PPA between Simplot and Idaho Power (Case No. IPC-E-04-16). In Order No. 32580, we stated "Given the agreement between the parties, the Commission did not address the REC ownership issue." Order No. 32580 at 11 *citing* Order No. 29577.

In summary, we find that the Commission has subject matter jurisdiction to decide the REC issues for the reasons set out above. We further find that it is fair and reasonable to apportion RECs equally between the QF and the utility when using IRP Methodology, and assign all RECs to the QF when using SAR Methodology.

H. Contracting Procedures and Rules

Proposals were made by multiple parties regarding Commission approval of contracting procedures and rules. The parties supported terms for contract milestones, timing of pricing, conditions for delivery of power, and other various informational requirements. We find that such procedures and rules would be beneficial to both the utilities and the QFs. We find that a fair and consistent set of rules for the utilities and QFs would reduce confusion and provide more certainty regarding the expectations of all contracting parties. We are optimistic that such rules might also reduce the number of complaints filed with this Commission because of disputes regarding contract terms. We direct the parties to participate in workshops with one another to begin to form a structure for fair and reasonable contracting procedures and rules. We expect the parties to submit to this Commission no later than December 13, 2013, a proposal for approval of such terms.

INTERVENOR FUNDING

On August 14, 2012, the Idaho Conservation League filed a request for intervenor funding in the amount of $8,100. The Canal Companies (Twin Falls Canal Company, North Side Canal Company, Big Wood Canal Company, and American Falls Reservoir District No. 2) filed a request for $55,445 in intervenor funds on August 21, 2012. Both applications were timely.

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and Commission Rules of Procedure 161 through 165. Section 61-617A(1) declares that it is "the policy of [Idaho] to encourage participation at all stages of all proceedings before this commission so that all affected customers receive full and fair representation in those proceedings." The statutory cap for intervenor funding that can be awarded in any one case is $40,000. *Idaho Code* § 61-617A(2). Accordingly, the Commission may order any regulated utility with intrastate annual revenues exceeding $3.5 million to pay all or a portion of the costs of one or more parties for legal fees, witness fees and reproduction costs not to exceed a total for all intervening parties combined of $40,000.

Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for a Petition for Intervenor Funding. The petition must contain: (1) an itemized list of expenses broken down into categories; (2) a statement of the intervenor's proposed finding or recommendation; (3) a statement showing that the costs the intervenor wishes to recover are reasonable; (4) a statement explaining why the costs constitute a significant financial hardship for the intervenor; (5) a statement showing how the intervenor's proposed finding or recommendation differed materially from the testimony and exhibits of the Commission Staff;

(6) a statement showing how the intervenor's recommendation or position addressed issues of concern to the general body of utility users or customers; and (7) a statement showing the class of customer on whose behalf the intervenor appeared.

1. Idaho Conservation League (ICL). ICL is a non-profit organization supported through charitable donations of members and foundations. ICL provided an itemized list of expenses totaling $8,187.50. The organization "rounded down for ease of accounting" and requests $8,100 in intervenor funding for attorney's fees incurred by participating in the case, reviewing the testimony, and representing ICL at the hearing. Petition at 2.

In its Petition, ICL states that it reviewed the case, opposed Idaho Power's Motion for a Temporary Stay, filed direct testimony, and actively participated in the evidentiary hearing. ICL further maintains that its position differed materially from that of Staff regarding ownership of renewable energy credits. ICL argued in briefing and at hearing that RECs are an independent property interest owned by the project developer. ICL also submitted testimony to rebut Idaho Power regarding its legal obligations on dams pursuant to the Clean Water Act. *Id.* at 4.

ICL maintains that, as a non-profit organization, its charitable contributions are inherently unstable. As such, the availability of intervenor funding is essential for ICL to participate in proceedings in front of the Commission. *Id.* ICL states that they have no pecuniary interest in the outcome, "rather we dedicated our time and resources to represent the interests of our 20,000 supporters around the state who have a strong interest in a robust clean energy industry in Idaho." *Id.*

ICL asserts that it addressed issues of concern for customers of all three utilities. "All customers, regardless of class, share a strong interest in ensuring Idaho utilities acquire power pursuant to rules that are fair, accurate, and conform to applicable laws." *Id.* Therefore, the organization suggests that the Commission allocate the responsibility for any intervenor funding award equally between the three utilities. *Id.* at 1. ICL maintains that both its hourly rate and hours expended are reasonable based on the complexity of this case. Petition at 2. ICL further states that its rates are "in line with the current range for other intervening parties." *Id.*

2. The Canal Companies. The Canal Companies provided an itemized list of partial expenses incurred during this proceeding. The Canal Companies assert that they seek an intervenor funding award only based on $55,445 in fees associated with retaining the expert

consulting services of Mr. Don Schoenbeck. Petition at 3. They do not request an award for the recovery of fees associated with legal counsel. *Id.* at 2.

In its Petition, the Canal Companies state that through the testimony of its witnesses, cross-examination of utility witnesses and in closing arguments, they advocated for 20-year contract length, 10 MW nameplate eligibility for published rates, and two-run simulations for IRP-based modeling. The Canal Companies also advocated an alternative for capacity payments and maintained that actual damages for breach of contract by a QF be determined through a "mark to market" approach. The Companies opposed Idaho Power's proposed curtailment tariff and advocated for QF ownership of RECs. The Canal Companies maintain that their various positions were materially different from Staff's.

The Canal Companies state that their members/owners are ratepayers of Idaho Power. *Id.* at 3. The Companies state that their funding for participation in this case is gained through a membership assessment fee. *Id.* The Canal Companies maintain that they addressed issues of concern for Idaho Power customers and in the public interest. "All customers, regardless of class, share a strong interest in ensuring Idaho utilities acquire power pursuant to rules that are fair, and accurate, and conform to applicable laws. . . . In addition, the involvement of Idaho's canal system in the production of inexpensive renewable energy provides a multiplier effect into the local economy. . . ." *Id.* at 5. The Canal Companies maintain that the customer classes they represent are residential and small commercial customers of Idaho Power and Rocky Mountain Power, "as well as QFs falling within the purview of Section 210 of PURPA allowing for sale and purchase of energy from investor-owned utilities." *Id.*

Commission Findings

The Commission has reviewed the Petitions for Intervenor Funding filed by ICL and the Canal Companies. We find that ICL contributed to discussions, debate and testimony and presented important perspectives that materially contributed to the Commission's decision-making in this case. Specifically, ICL presented testimony and cross-examination regarding Idaho Power's dams and must-run requirements that prompted meaningful discussion regarding the breadth of Idaho Power's proposed curtailment tariff.

The Commission finds that ICL's participation contributed to our deliberations in this matter and presented positions different from that of Staff and other utility and intervenor witnesses. We further find that $8,100 is a reasonable amount in costs and fees based on ICL's level of participation at all phases of this proceeding and that these costs would otherwise amount to a financial hardship for the organization. Therefore, we find that it is just and reasonable to grant ICL intervenor funding in the amount of $8,100. Pursuant to *Idaho Code* § 61-617A(3), the amount awarded to ICL shall be recovered from Avista, Idaho Power and Rocky Mountain Power based on a proportional share of the total number of Idaho customers served by each utility.

We find that the Canal Companies participation also contributed to the positions advanced by the parties to this case. Mr. Schoenbeck's testimony advanced a reasonable approach on several issues that otherwise divided the utilities and the QFs. However, in considering the reasonableness of the request for intervenor funding made by the Canal Companies, the Commission is required to consider whether the payment of the amount requested by the intervenors would constitute a "significant financial hardship." *Idaho Code* § 61-617A(2)(b); IDAPA 31.01.01.162.04. The Canal Companies made no mention of whether and to what extent their participation and commensurate expenses would amount to a significant financial hardship for their members. We find that a showing of financial hardship is critical for an award of intervenor funds. Therefore, we deny any award of intervenor funding to the Canal Companies based on their failure to comply with the requirements of *Idaho Code* § 61-617A(2).

ULTIMATE FINDINGS AND CONCLUSIONS

The Commission has jurisdiction over this matter pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA). The Commission has authority under PURPA and its implementing regulations to set avoided costs, to establish standard published avoided cost rates, to order electric utilities to enter into fixed-term obligations for the purchase of energy from QFs, and to implement FERC regulations. The Commission is also empowered to resolve complaints between QFs and utilities and approve QF contracts.

Under PURPA, utilities are required to purchase QF generation at a rate equal to the utility's avoided cost. 18 C.F.R. § 292.304(b)(2). "Avoided costs" are the incremental costs to the electric utility of power which, but for the purchase from the QF, such utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6). PURPA and FERC regulations direct not only that rates for purchases shall not discriminate against QFs, but also that avoided cost rates be just and reasonable to the utility's ratepayers and in the public interest. 18 C.F.R. § 292.304(a)(1).

Although FERC promulgated the general scheme and rules, it left the actual implementation of PURPA to the state regulatory authorities. *Rosebud Enterprises, Inc. v. Idaho Public Utilities Commission*, 128 Idaho 609, 614, 917 P.2d 766, 771 (1996). FERC regulations grant the states latitude in implementing the regulation of sales and purchases between QFs and electric utilities. *See Federal Energy Regulatory Commission v. Mississippi*, 456 U.S. 742, 102 S.Ct. 2126, 72 L.Ed.2d 532 (1982).

As we have stated previously in this docket and other PURPA related matters, this Commission has a long history of encouraging PURPA development. With the changes adopted herein, we believe that PURPA development can continue to thrive in a way that holds ratepayers harmless. QF projects will be compensated according to their ability to provide a utility with needed energy and capacity at a rate that reflects the costs that the utility avoids by purchasing QF generation. Our findings regarding calculation of avoided costs, eligibility to published rates, RECs and performance security, terms and conditions within contracts, and length of contracts are entirely consistent with PURPA and FERC regulations.

ORDER

IT IS HEREBY ORDERED that published avoided cost rates are available for wind and solar projects producing up to 100 kW. Published rates for all other resources are available for projects producing up to 10 aMW.

IT IS FURTHER ORDERED that qualifying facilities not receive compensation for capacity until the utility is capacity deficient.

IT IS FURTHER ORDERED that natural gas prices utilized in the SAR Methodology be updated annually, on June 1 of each year, with the most recent natural gas forecasts provided by EIA's Annual Energy Outlook.

IT IS FURTHER ORDERED that fuel price forecasts and load forecasts utilized in the IRP Methodology be updated annually, on June 1 of each year. In addition, long-term contracts shall be considered in IRP Methodology calculations at such time as the utility and QF have entered into a signed contract for the sale and purchase of QF power.

IT IS FURTHER ORDERED that a utility's determination of capacity deficiency through its IRP planning process shall be subject to additional scrutiny for use within the SAR

Methodology. We continue the remainder of the IRP planning process as it is currently constituted.

IT IS FURTHER ORDERED that we adopt and approve the Partial Settlement Stipulation regarding security deposits, delay damages, refunds, and termination damages in its entirety.

IT IS FURTHER ORDERED that RECs for SAR based projects will be owned by the QF. RECs produced by projects utilizing the IRP Methodology will be equally apportioned between the utility and QF in the manner of their choosing.

IT IS FURTHER ORDERED that Idaho Power's proposed Schedule 74 is not approved.

IT IS FURTHER ORDERED that additional pricing calculations, contract provisions, terms and conditions shall comply with the findings of this Commission as set out in greater detail in the body of this Order.

IT IS FURTHER ORDERED that ICL's Petition for Intervenor Funding is granted in the amount of $8,100. The utilities are directed to remit this amount to ICL within 28 days from the date of this Order and as more specifically described herein. IDAPA 31.01.01.165.02.

IT IS FURTHER ORDERED that the Canal Companies Petition for Intervenor Funding is denied.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 18th day of December 2012.

PAUL KJELLANDER, PRESIDENT

MACK A. REDFORD, COMMISSIONER

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

O:GNR-E-11-03_ks_dh_Final Order

IDAHO POWER COMPANY
AVOIDED COST RATES FOR WIND PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	22.04	21.73	24.35	27.21	28.09	38.48	2012	22.04
2	21.89	22.99	25.72	27.63	33.08	39.13	2013	21.73
3	22.65	24.29	26.45	30.97	35.16	39.88	2014	24.35
4	23.66	25.13	29.11	32.93	36.58	40.49	2015	27.21
5	24.41	27.39	30.93	34.40	37.61	41.43	2016	28.09
6	26.32	29.08	32.38	35.52	38.75	42.55	2017	38.48
7	27.83	30.47	33.52	36.68	39.97	43.67	2018	39.84
8	29.11	31.61	34.69	37.90	41.15	44.68	2019	41.56
9	30.18	32.75	35.88	39.07	42.21	45.60	2020	42.64
10	31.27	33.92	37.02	40.13	43.16	46.48	2021	46.00
11	32.36	35.03	38.06	41.08	44.08	47.38	2022	49.71
12	33.42	36.04	39.01	41.99	44.99	48.25	2023	52.58
13	34.39	36.97	39.90	42.89	45.87	49.06	2024	54.52
14	35.28	37.84	40.79	43.75	46.69	49.86	2025	56.18
15	36.12	38.71	41.63	44.56	47.49	50.65	2026	58.48
16	36.95	39.53	42.42	45.34	48.27	51.42	2027	61.63
17	37.74	40.30	43.19	46.11	49.03	52.17	2028	64.00
18	38.48	41.05	43.93	46.85	49.77	52.94	2029	66.03
19	39.19	41.77	44.65	47.57	50.52	53.73	2030	68.69
20	39.89	42.47	45.35	48.30	51.29	54.48	2031	71.49
							2032	74.37
							2033	77.18
							2034	81.63
							2035	86.29
							2036	88.46
							2037	92.22

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR SOLAR PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	18.70	18.32	26.37	50.46	51.66	66.06	2012	18.70
2	18.52	22.19	37.94	51.04	58.58	66.91	2013	18.32
3	20.93	30.88	42.16	55.66	61.43	67.85	2014	26.37
4	27.47	35.48	47.45	58.35	63.31	68.65	2015	50.46
5	31.58	40.68	50.91	60.32	64.70	69.77	2016	51.66
6	36.26	44.36	53.50	61.84	66.13	71.07	2017	66.06
7	39.78	47.21	55.50	63.33	67.60	72.37	2018	67.83
8	42.60	49.48	57.34	64.83	69.01	73.55	2019	69.96
9	44.89	51.53	59.09	66.25	70.29	74.63	2020	71.46
10	46.97	53.43	60.71	67.53	71.44	75.68	2021	75.24
11	48.90	55.17	62.16	68.70	72.54	76.74	2022	79.38
12	50.66	56.73	63.46	69.81	73.64	77.76	2023	82.67
13	52.24	58.13	64.68	70.90	74.68	78.73	2024	85.06
14	53.66	59.42	65.85	71.94	75.67	79.68	2025	87.16
15	54.98	60.66	66.96	72.91	76.62	80.61	2026	89.91
16	56.23	61.82	68.00	73.86	77.55	81.52	2027	93.53
17	57.40	62.90	68.99	74.78	78.46	82.41	2028	96.37
18	58.49	63.93	69.94	75.66	79.34	83.32	2029	98.86
19	59.52	64.91	70.86	76.52	80.23	84.24	2030	102.01
20	60.50	65.85	71.74	77.39	81.13	85.11	2031	105.30
							2032	108.67
							2033	111.99
							2034	116.94
							2035	122.12
							2036	124.82
							2037	129.11

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR HYDRO PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	23.31	23.03	27.53	37.64	38.68	47.83	2012	23.31
2	23.18	25.19	32.39	38.14	43.07	48.55	2013	23.03
3	24.52	29.02	34.32	41.12	45.00	49.36	2014	27.53
4	27.42	31.16	37.31	42.93	46.37	50.03	2015	37.64
5	29.33	33.99	39.35	44.34	47.39	51.03	2016	38.68
6	31.84	36.07	40.96	45.43	48.55	52.22	2017	47.83
7	33.79	37.75	42.23	46.60	49.80	53.39	2018	49.33
8	35.42	39.12	43.51	47.83	51.01	54.47	2019	51.19
9	36.77	40.46	44.80	49.02	52.11	55.44	2020	52.41
10	38.08	41.78	46.03	50.10	53.11	56.37	2021	55.91
11	39.37	43.03	47.15	51.09	54.06	57.33	2022	59.77
12	40.59	44.17	48.17	52.03	55.02	58.25	2023	62.78
13	41.70	45.20	49.14	52.97	55.94	59.12	2024	64.87
14	42.72	46.18	50.09	53.86	56.80	59.97	2025	66.68
15	43.68	47.13	50.99	54.71	57.64	60.80	2026	69.13
16	44.62	48.04	51.84	55.53	58.47	61.62	2027	72.44
17	45.50	48.88	52.66	56.33	59.27	62.42	2028	74.97
18	46.33	49.70	53.45	57.11	60.05	63.24	2029	77.15
19	47.13	50.49	54.22	57.86	60.84	64.07	2030	79.98
20	47.89	51.25	54.97	58.63	61.65	64.86	2031	82.95
							2032	86.00
							2033	88.98
							2034	93.59
							2035	98.43
							2036	100.78
							2037	104.72

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR CANAL DROP HYDRO PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	23.31	23.03	27.53	73.60	75.17	84.85	2012	23.31
2	23.18	25.19	49.66	74.36	79.82	85.83	2013	23.03
3	24.52	40.08	57.51	77.58	81.99	86.90	2014	27.53
4	35.38	47.85	63.56	79.64	83.61	87.82	2015	73.60
5	42.14	54.13	67.52	81.28	84.88	89.07	2016	75.17
6	47.93	58.58	70.48	82.61	86.27	90.49	2017	84.85
7	52.28	62.00	72.77	84.01	87.75	91.90	2018	86.89
8	55.73	64.72	74.86	85.46	89.19	93.21	2019	89.30
9	58.54	67.13	76.83	86.87	90.52	94.40	2020	91.08
10	61.05	69.35	78.63	88.17	91.73	95.56	2021	95.14
11	63.34	71.37	80.25	89.36	92.90	96.73	2022	99.57
12	65.42	73.16	81.71	90.51	94.06	97.86	2023	103.17
13	67.28	74.78	83.07	91.65	95.18	98.94	2024	105.85
14	68.95	76.27	84.38	92.74	96.24	99.99	2025	108.26
15	70.49	77.68	85.62	93.77	97.28	101.02	2026	111.32
16	71.94	79.01	86.77	94.78	98.28	102.02	2027	115.25
17	73.29	80.24	87.88	95.75	99.27	103.00	2028	118.40
18	74.55	81.40	88.94	96.71	100.22	104.00	2029	121.22
19	75.74	82.51	89.96	97.63	101.19	105.01	2030	124.69
20	76.87	83.57	90.94	98.56	102.16	105.96	2031	128.32
							2032	132.03
							2033	135.68
							2034	140.99
							2035	146.52
							2036	149.58
							2037	154.23

Note: A "canal drop hydro project" is defined as a generation facility which produces the majority of its generation during the irrigation season and is located on a man-made waterway that conveys water primarily intended for irrigation or that primarily conveys irrigation return flows.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR OTHER PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017
1	26.49	26.26	28.33	51.58	52.85	58.72
2	26.38	27.26	39.50	52.19	55.67	59.51
3	26.98	34.74	43.60	54.20	57.11	60.40
4	32.43	38.75	46.95	55.56	58.28	61.15
5	35.89	42.14	49.23	56.72	59.22	62.22
6	38.99	44.61	51.02	57.68	60.33	63.47
7	41.37	46.59	52.44	58.77	61.58	64.72
8	43.34	48.20	53.84	59.96	62.80	65.86
9	44.96	49.73	55.24	61.13	63.92	66.90
10	46.50	51.22	56.57	62.21	64.95	67.90
11	47.99	52.61	57.78	63.20	65.93	68.92
12	49.38	53.88	58.88	64.16	66.93	69.90
13	50.64	55.03	59.93	65.12	67.89	70.83
14	51.80	56.11	60.95	66.04	68.79	71.74
15	52.88	57.16	61.92	66.91	69.68	72.63
16	53.92	58.15	62.84	67.76	70.54	73.50
17	54.91	59.09	63.72	68.60	71.39	74.36
18	55.83	59.98	64.58	69.41	72.21	75.23
19	56.71	60.84	65.40	70.20	73.04	76.11
20	57.56	61.67	66.20	71.00	73.89	76.95

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2012	26.49
2013	26.26
2014	28.33
2015	51.58
2016	52.85
2017	58.72
2018	60.38
2019	62.40
2020	63.78
2021	67.45
2022	71.48
2023	74.66
2024	76.92
2025	78.91
2026	81.54
2027	85.03
2028	87.75
2029	90.12
2030	93.13
2031	96.29
2032	99.54
2033	102.71
2034	107.53
2035	112.57
2036	115.13
2037	119.28

Note: "Other projects" refers to projects other than wind, solar, hydro, and canal drop hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

AVISTA
AVOIDED COST RATES FOR WIND PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	21.31	20.98	20.71	23.53	24.36	25.25	2012	21.31
2	21.15	20.85	22.06	23.93	24.79	25.78	2013	20.98
3	21.01	21.67	22.77	24.34	25.27	26.40	2014	20.71
4	21.57	22.26	23.31	24.78	25.82	29.98	2015	23.53
5	22.04	22.77	23.83	25.29	28.67	32.69	2016	24.36
6	22.47	23.25	24.36	27.63	31.00	34.98	2017	25.25
7	22.90	23.75	26.38	29.66	33.07	36.93	2018	26.35
8	23.35	25.49	28.19	31.51	34.87	38.55	2019	27.79
9	24.86	27.10	29.88	33.16	36.41	39.94	2020	42.69
10	26.29	28.63	31.41	34.60	37.74	41.19	2021	46.04
11	27.66	30.03	32.76	35.86	38.96	42.38	2022	49.76
12	28.93	31.28	33.96	37.02	40.12	43.49	2023	52.62
13	30.08	32.40	35.06	38.12	41.19	44.50	2024	54.56
14	31.12	33.43	36.11	39.15	42.18	45.46	2025	56.22
15	32.08	34.43	37.10	40.10	43.11	46.38	2026	58.52
16	33.02	35.36	38.01	41.00	44.01	47.26	2027	61.68
17	33.89	36.23	38.88	41.86	44.87	48.11	2028	64.05
18	34.71	37.05	39.70	42.69	45.69	48.96	2029	66.07
19	35.48	37.84	40.50	43.48	46.51	49.81	2030	68.74
20	36.22	38.59	41.25	44.26	47.32	50.61	2031	71.54
							2032	74.42
							2033	77.23
							2034	81.68
							2035	86.34
							2036	88.51
							2037	92.27

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

AVISTA
AVOIDED COST RATES FOR SOLAR PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	17.49	17.08	16.73	19.48	20.23	21.04	2012	17.49
2	17.29	16.91	18.05	19.84	20.61	21.52	2013	17.08
3	17.12	17.70	18.72	20.20	21.05	22.10	2014	16.73
4	17.64	18.25	19.23	20.61	21.57	33.06	2015	19.48
5	18.08	18.72	19.70	21.08	30.05	40.24	2016	20.23
6	18.47	19.17	20.20	27.91	36.19	45.56	2017	21.04
7	18.87	19.64	25.90	33.17	40.99	46.51	2018	22.05
8	19.29	24.45	30.48	37.47	42.21	47.39	2019	23.40
9	23.40	28.46	34.34	38.78	43.29	48.21	2020	71.88
10	26.92	31.91	35.67	39.94	44.27	49.01	2021	75.67
11	30.00	33.21	36.87	40.98	45.19	49.84	2022	79.81
12	31.23	34.38	37.93	41.96	46.12	50.65	2023	54.14
13	32.35	35.43	38.93	42.92	46.99	51.41	2024	56.11
14	33.36	36.41	39.90	43.82	47.82	52.17	2025	57.79
15	34.30	37.36	40.81	44.66	48.61	52.91	2026	60.11
16	35.22	38.25	41.65	45.47	49.39	53.64	2027	63.29
17	36.08	39.08	42.46	46.26	50.14	54.36	2028	65.69
18	36.88	39.87	43.24	47.01	50.87	55.10	2029	67.73
19	37.64	40.63	43.99	47.74	51.62	55.85	2030	70.42
20	38.37	41.36	44.71	48.48	52.37	56.56	2031	73.25
							2032	76.16
							2033	78.99
							2034	83.46
							2035	88.15
							2036	90.35
							2037	94.13

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

AVISTA
AVOIDED COST RATES FOR HYDRO PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	22.76	22.46	22.22	25.08	25.93	26.86	2012	22.76
2	22.62	22.34	23.59	25.49	26.38	27.40	2013	22.46
3	22.49	23.18	24.31	25.91	26.87	28.03	2014	22.22
4	23.06	23.79	24.87	26.37	27.44	33.44	2015	25.08
5	23.55	24.30	25.39	26.89	31.68	37.25	2016	25.93
6	23.99	24.80	25.94	30.34	34.96	40.30	2017	26.86
7	24.43	25.31	28.88	33.18	37.71	44.30	2018	27.99
8	24.90	27.83	31.38	35.64	41.30	47.49	2019	29.46
9	27.06	30.04	33.62	38.85	44.24	50.11	2020	52.58
10	29.01	32.05	36.51	41.54	46.70	52.36	2021	56.08
11	30.82	34.65	38.98	43.84	48.86	54.38	2022	59.94
12	33.15	36.90	41.12	45.86	50.80	56.19	2023	76.60
13	35.21	38.88	43.02	47.71	52.56	57.81	2024	78.89
14	37.02	40.65	44.77	49.39	54.13	59.30	2025	80.91
15	38.66	42.29	46.36	50.90	55.58	60.68	2026	83.57
16	40.19	43.79	47.81	52.30	56.93	61.97	2027	87.09
17	41.59	45.15	49.15	53.60	58.20	63.18	2028	89.83
18	42.87	46.42	50.39	54.82	59.38	64.36	2029	92.23
19	44.06	47.61	51.56	55.96	60.53	65.51	2030	95.28
20	45.18	48.72	52.66	57.06	61.65	66.58	2031	98.47
							2032	101.75
							2033	104.96
							2034	109.81
							2035	114.88
							2036	117.48
							2037	121.66

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

AVISTA
AVOIDED COST RATES FOR CANAL DROP HYDRO PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	22.76	22.46	22.22	25.08	25.93	26.86	2012	22.76
2	22.62	22.34	23.59	25.49	26.38	27.40	2013	22.46
3	22.49	23.18	24.31	25.91	26.87	28.03	2014	22.22
4	23.06	23.79	24.87	26.37	27.44	42.06	2015	25.08
5	23.55	24.30	25.39	26.89	38.29	51.13	2016	25.93
6	23.99	24.80	25.94	35.61	46.02	57.74	2017	26.86
7	24.43	25.31	33.19	42.25	52.00	56.81	2018	27.99
8	24.90	31.44	38.97	47.59	51.75	56.29	2019	29.46
9	30.13	36.48	43.77	47.73	51.71	56.02	2020	91.77
10	34.55	40.77	44.14	47.96	51.79	55.96	2021	95.84
11	38.38	41.27	44.55	48.25	51.98	56.08	2022	100.28
12	38.94	41.77	44.97	48.59	52.29	56.31	2023	49.31
13	39.49	42.27	45.43	49.02	52.66	56.59	2024	51.21
14	40.02	42.78	45.93	49.48	53.05	56.92	2025	52.82
15	40.55	43.32	46.45	49.94	53.47	57.31	2026	55.07
16	41.11	43.86	46.95	50.41	53.93	57.73	2027	58.17
17	41.65	44.39	47.46	50.90	54.40	58.17	2028	60.50
18	42.18	44.91	47.98	51.40	54.88	58.67	2029	62.46
19	42.70	45.43	48.49	51.91	55.40	59.21	2030	65.07
20	43.22	45.95	49.01	52.44	55.96	59.73	2031	67.83
							2032	70.65
							2033	73.41
							2034	77.80
							2035	82.40
							2036	84.52
							2037	88.22

Note: A "canal drop hydro project" is defined as a generation facility which produces the majority of its generation during the irrigation season and is located on a man-made waterway that conveys water primarily intended for irrigation or that primarily conveys irrigation return flows.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

AVISTA
AVOIDED COST RATES FOR OTHER PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	26.39	26.16	25.99	28.92	29.86	30.86	2012	26.39
2	26.28	26.08	27.40	29.37	30.34	31.44	2013	26.16
3	26.19	26.95	28.15	29.83	30.87	32.11	2014	25.99
4	26.79	27.59	28.75	30.32	31.48	39.15	2015	28.92
5	27.31	28.14	29.31	30.88	36.98	43.98	2016	29.86
6	27.79	28.67	29.89	35.35	41.12	47.72	2017	30.86
7	28.26	29.22	33.66	38.92	44.50	50.73	2018	32.07
8	28.75	32.43	36.80	41.95	47.31	53.17	2019	33.62
9	31.52	35.20	39.54	44.54	49.65	55.21	2020	64.11
10	33.96	37.66	41.93	46.74	51.64	57.01	2021	67.78
11	36.17	39.84	43.99	48.63	53.41	58.66	2022	71.81
12	38.15	41.75	45.79	50.33	55.04	60.16	2023	74.99
13	39.90	43.43	47.41	51.90	56.52	61.52	2024	77.26
14	41.46	44.96	48.91	53.34	57.87	62.79	2025	79.25
15	42.89	46.38	50.30	54.65	59.13	63.99	2026	81.89
16	44.23	47.70	51.56	55.87	60.31	65.12	2027	85.39
17	45.46	48.90	52.74	57.02	61.43	66.19	2028	88.11
18	46.60	50.03	53.86	58.11	62.48	67.25	2029	90.48
19	47.67	51.09	54.91	59.13	63.52	68.29	2030	93.50
20	48.68	52.10	55.90	60.14	64.53	69.26	2031	96.67
							2032	99.92
							2033	103.10
							2034	107.92
							2035	112.97
							2036	115.54
							2037	119.69

Note: "Other projects" refers to projects other than wind, solar, hydro, and canal drop hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

PACIFICORP
AVOIDED COST RATES FOR WIND PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	18.62	18.25	20.74	23.51	24.31	25.18	2012	18.62
2	18.45	19.45	22.07	23.89	24.73	32.20	2013	18.25
3	19.15	20.70	22.76	24.29	29.36	35.06	2014	20.74
4	20.12	21.50	23.30	27.73	32.06	36.73	2015	23.51
5	20.83	22.13	26.11	30.08	33.85	38.30	2016	24.31
6	21.43	24.54	28.21	31.78	35.50	39.85	2017	25.18
7	23.48	26.44	29.82	33.37	37.09	41.27	2018	39.78
8	25.18	27.96	31.33	34.90	38.54	42.51	2019	41.49
9	26.57	29.40	32.80	36.31	39.81	43.60	2020	42.58
10	27.91	30.80	34.16	37.56	40.94	44.62	2021	45.93
11	29.22	32.10	35.38	38.68	41.99	45.64	2022	49.64
12	30.45	33.28	36.48	39.72	43.02	46.60	2023	52.51
13	31.56	34.34	37.50	40.74	43.99	47.50	2024	54.45
14	32.58	35.34	38.49	41.70	44.90	48.38	2025	56.10
15	33.53	36.31	39.43	42.59	45.78	49.23	2026	58.40
16	34.46	37.22	40.31	43.45	46.62	50.05	2027	61.56
17	35.33	38.07	41.15	44.28	47.44	50.86	2028	63.93
18	36.15	38.89	41.96	45.08	48.24	51.68	2029	65.95
19	36.94	39.67	42.74	45.86	49.04	52.51	2030	68.61
20	37.69	40.43	43.49	46.64	49.86	53.30	2031	71.41
							2032	74.29
							2033	77.10
							2034	81.54
							2035	86.20
							2036	88.38
							2037	92.13

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

ATTACHMENT C
ORDER NO. 32697
CASE NO. GNR-E-11-03

PACIFICORP
AVOIDED COST RATES FOR SOLAR PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	13.85	13.38	41.62	44.66	45.74	46.90	2012	13.85
2	13.62	26.96	43.08	45.18	46.30	56.64	2013	13.38
3	22.25	32.41	43.90	45.71	52.73	60.53	2014	41.62
4	27.22	35.37	44.56	50.47	56.40	62.81	2015	44.66
5	30.38	37.34	48.42	53.68	58.85	64.81	2016	45.74
6	32.63	41.40	51.26	56.01	60.99	66.70	2017	46.90
7	36.51	44.53	53.45	58.09	62.97	68.41	2018	67.16
8	39.59	47.00	55.43	60.02	64.76	69.90	2019	69.28
9	42.09	49.20	57.30	61.78	66.33	71.23	2020	70.77
10	44.33	51.24	59.00	63.34	67.71	72.47	2021	74.54
11	46.39	53.09	60.52	64.73	69.00	73.69	2022	78.67
12	48.27	54.74	61.89	66.02	70.26	74.84	2023	81.95
13	49.95	56.21	63.16	67.26	71.44	75.93	2024	84.32
14	51.46	57.57	64.38	68.43	72.54	76.97	2025	86.42
15	52.85	58.87	65.54	69.53	73.60	77.99	2026	89.16
16	54.17	60.09	66.61	70.57	74.62	78.97	2027	92.77
17	55.40	61.21	67.64	71.58	75.60	79.93	2028	95.60
18	56.54	62.28	68.62	72.55	76.56	80.90	2029	98.08
19	57.62	63.30	69.57	73.48	77.51	81.87	2030	101.21
20	58.65	64.28	70.48	74.42	78.47	82.79	2031	104.49
							2032	107.86
							2033	111.16
							2034	116.10
							2035	121.27
							2036	123.96
							2037	128.23

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

PACIFICORP
AVOIDED COST RATES FOR HYDRO PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	20.44	20.10	31.39	34.32	35.29	36.33	2012	20.44
2	20.28	25.53	32.80	34.79	35.79	42.45	2013	20.10
3	23.70	28.24	33.57	35.26	39.88	45.06	2014	31.39
4	26.06	29.80	34.18	38.32	42.33	46.63	2015	34.32
5	27.63	30.92	36.72	40.47	44.00	48.16	2016	35.29
6	28.82	33.39	38.65	42.06	45.58	49.71	2017	36.33
7	31.09	35.36	40.16	43.58	47.14	51.14	2018	49.06
8	32.95	36.93	41.62	45.08	48.59	52.40	2019	50.91
9	34.49	38.43	43.05	46.47	49.87	53.52	2020	52.13
10	35.95	39.89	44.39	47.72	51.01	54.58	2021	55.63
11	37.37	41.25	45.61	48.85	52.08	55.64	2022	59.48
12	38.69	42.48	46.70	49.90	53.14	56.64	2023	62.49
13	39.90	43.59	47.73	50.94	54.14	57.58	2024	64.57
14	40.99	44.63	48.74	51.92	55.08	58.49	2025	66.38
15	42.02	45.65	49.70	52.84	55.99	59.38	2026	68.83
16	43.01	46.61	50.60	53.72	56.87	60.25	2027	72.13
17	43.95	47.50	51.46	54.58	57.72	61.09	2028	74.66
18	44.83	48.36	52.29	55.41	58.55	61.95	2029	76.84
19	45.68	49.19	53.10	56.22	59.39	62.83	2030	79.66
20	46.48	49.99	53.88	57.03	60.23	63.65	2031	82.62
							2032	85.67
							2033	88.64
							2034	93.25
							2035	98.08
							2036	100.44
							2037	104.36

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

PACIFICORP
AVOIDED COST RATES FOR CANAL DROP HYDRO PROJECTS
December 13, 2012

$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	20.44	20.10	66.07	69.50	70.99	72.55	2012	20.44
2	20.28	42.20	67.72	70.22	71.74	78.92	2013	20.10
3	34.39	50.62	68.73	70.94	76.07	81.78	2014	66.07
4	42.18	55.14	69.58	74.24	78.77	83.60	2015	69.50
5	47.09	58.11	72.34	76.62	80.68	85.37	2016	70.99
6	50.57	61.89	74.51	78.44	82.49	87.15	2017	72.55
7	54.52	64.84	76.24	80.19	84.28	88.82	2018	85.81
8	57.69	67.20	77.91	81.90	85.95	90.31	2019	88.20
9	60.27	69.35	79.56	83.51	87.45	91.65	2020	89.96
10	62.61	71.36	81.11	84.97	88.80	92.93	2021	94.01
11	64.76	73.20	82.52	86.30	90.09	94.20	2022	98.43
12	66.72	74.86	83.82	87.56	91.35	95.41	2023	102.00
13	68.49	76.36	85.04	88.79	92.55	96.55	2024	104.67
14	70.09	77.76	86.24	89.96	93.68	97.66	2025	107.06
15	71.56	79.09	87.38	91.07	94.78	98.75	2026	110.11
16	72.97	80.35	88.46	92.14	95.85	99.80	2027	114.02
17	74.28	81.53	89.50	93.17	96.88	100.83	2028	117.16
18	75.50	82.65	90.50	94.18	97.88	101.86	2029	119.96
19	76.66	83.72	91.47	95.15	98.89	102.91	2030	123.41
20	77.76	84.75	92.41	96.12	99.90	103.90	2031	127.02
							2032	130.71
							2033	134.35
							2034	139.63
							2035	145.14
							2036	148.18
							2037	152.81

Note: A "canal drop hydro project" is defined as a generation facility which produces the majority of its generation during the irrigation season and is located on a man-made waterway that conveys water primarily intended for irrigation or that primarily conveys irrigation return flows.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

PACIFICORP
AVOIDED COST RATES FOR OTHER PROJECTS
December 13, 2012
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	24.97	24.73	46.31	49.48	50.70	51.99	2012	24.97
2	24.85	35.10	47.83	50.06	51.32	55.78	2013	24.73
3	31.46	39.53	48.71	50.66	53.95	57.66	2014	46.31
4	35.46	42.01	49.44	52.70	55.71	58.90	2015	49.48
5	38.06	43.71	51.22	54.27	57.00	60.27	2016	50.70
6	39.96	45.91	52.67	55.49	58.35	61.72	2017	51.99
7	42.19	47.71	53.86	56.77	59.76	63.11	2018	59.86
8	44.04	49.17	55.09	58.11	61.11	64.36	2019	61.88
9	45.58	50.59	56.36	59.39	62.33	65.48	2020	63.26
10	47.06	52.00	57.58	60.56	63.44	66.55	2021	66.92
11	48.49	53.33	58.71	61.63	64.49	67.63	2022	70.94
12	49.85	54.54	59.75	62.65	65.55	68.66	2023	74.11
13	51.08	55.65	60.74	63.67	66.55	69.63	2024	76.37
14	52.21	56.70	61.72	64.64	67.50	70.58	2025	78.34
15	53.27	57.72	62.66	65.56	68.43	71.50	2026	80.97
16	54.30	58.69	63.54	66.45	69.33	72.41	2027	84.45
17	55.27	59.61	64.40	67.31	70.21	73.29	2028	87.16
18	56.19	60.49	65.24	68.16	71.06	74.19	2029	89.52
19	57.07	61.34	66.06	68.98	71.92	75.10	2030	92.53
20	57.92	62.16	66.84	69.81	72.80	75.96	2031	95.68
							2032	98.92
							2033	102.08
							2034	106.89
							2035	111.92
							2036	114.48
							2037	118.61

Note: "Other projects" refers to projects other than wind, solar, hydro, and canal drop hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.