Office of the Secretary
Service Date
May 6, 2013

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. 32802**

On December 18, 2012, the Commission issued final Order No. 32697 determining various issues related to avoided cost rate methodologies and other considerations regarding Public Utility Regulatory Policies Act (PURPA) contracts. On January 8, 2013, Idaho Power Company, Renewable Northwest Project, Renewable Energy Coalition, Idaho Conservation League and J.R. Simplot/Clearwater Paper filed timely requests for reconsideration/clarification.

Commission Staff and Idaho Wind Partners filed timely answers to the petitions. Idaho Power filed what it captioned as a "Response and Cross-Petition" within the time allowed for answers. On January 22, 2013, Mountain Air Projects filed an untimely answer to the petitions. On January 23, 2013, the Canal Companies filed what was captioned as a "Reply" to Idaho Power's Response and Cross-Petition.

RECONSIDERATION

Reconsideration provides an opportunity for a party to bring to the Commission's attention any question previously determined and thereby affords the Commission with an opportunity to rectify any mistake or omission. *Washington Water Power Co. v. Kootenai Environmental Alliance*, 99 Idaho 875, 879, 591 P.2d 122, 126 (1979). The Commission may grant reconsideration by reviewing the existing record, by written briefs, or by evidentiary hearing. IDAPA 31.01.01.332.

On February 5, 2013, the Commission issued Order No. 32737 partially granting and partially denying reconsideration/clarification. The Commission granted reconsideration on the issues related to ownership of renewable energy credits (RECs). The Commission chose to reconsider the REC issues based on the existing record. We also granted reconsideration of the SAR methodology issues surrounding the definition of canal drop hydro and proper capacity factors for hydro and "other" projects. Discovery, comments and reply were permitted on the canal drop hydro and capacity factor issues.

The Commission took the opportunity to clarify that, in its final Order No. 32697; it did not implicitly or explicitly authorize contract extensions or renewals for existing contracts that do not contain such provisions. Order No. 32737 at 5. The Commission explained that "when an existing QF under a current contract desires to continue to sell energy to the same utility after expiration of the current contract, and the parties enter into a new contract for the sale and purchase of energy, the QF is entitled to be paid capacity for the full term of the new agreement." *Id.* The Commission also directed Staff to provide published rate tables for replacement contracts upon request by any interested party.

The Commission clarified its determination of capacity deficiency. We stated that, "the SAR model recognizes not only the timing of when the first deficit occurs, but also the magnitude of the deficit. . . . As the utility's deficit grows, increasing amounts of the QF's capacity are given credit until the year when the utility's deficit exceeds the QF's capacity, when full value for the QF's capacity is given." *Id.* at 8.

The Commission further granted clarification on the issue of annual updates to the utilities' gas and load forecasts. In acknowledgement that the final EIA gas forecast might be released after June 1 in any given year, the Commission clarified that the annual update of the EIA gas forecast utilized within the SAR methodology should occur "on June 1 or within 30 days of the final release of the EIA Annual Energy Outlook, whichever is later." *Id.* at 7. The Commission also directed the utilities to collaborate and propose a suitable date for all three utilities to update their gas and load forecasts used in their IRP methodologies.

The Commission denied Idaho Power's request to clarify the Commission's findings regarding curtailment and the application of 18 C.F.R. § 292.304(f). The Commission further denied reconsideration of its findings regarding use of incremental costs in determining avoided costs under the IRP Methodology. *Id.* at 8.

By this Order, we address the narrow issues of annual updates to gas and load forecasts, canal drop hydro concerns, resource specific capacity factors, and REC ownership which were granted reconsideration by Order No. 32737.

UPDATES TO GAS AND LOAD FORECASTS

In the Commission's final Order, we determined that the natural gas price forecast used in the SAR model and the fuel and load forecasts used in the IRP Methodology should be updated every June 1 utilizing data from the EIA's Annual Energy Outlook. Order No. 32697 at 52. Idaho Power requested clarification of the Commission's determination regarding fuel and load forecast updates in two respects. First, Idaho Power proposed that the Commission consider updating the SAR model "immediately upon release of the specifically designated EIA natural gas price forecast" instead of waiting until June 1 in order to avoid "gamesmanship." Petition at 8. Second, Idaho Power stated that the Company does not update its fuel and load forecasts utilized in the IRP Methodology until October of each year. Consequently, Idaho Power requested that annual updates to the fuel and load forecasts utilized in its IRP Methodology be set for a different date.

The Commission determined that a single date for annual updates to both the SAR and IRP methodologies was not required. "However, to avoid confusion, ensure consistency, and alleviate gamesmanship, we find it necessary for all three utilities to update their annual SAR gas forecast on the same date, and to also update their annual IRP forecasts on a uniform date." Order No. 32737 at 6. The Commission clarified that "the annual update of the EIA gas forecast should occur on June 1 <u>or within 30 days of the final release of the EIA Annual Energy Outlook, whichever is later</u>." *Id.* at 7 (emphasis in original).

The Commission also directed the three utilities to collaborate and propose a suitable date for all three utilities to update their gas and load forecasts used in their IRP methodologies. The utilities filed notice with the Commission on March 5, 2013, that they consulted and agreed that each utility should update the natural gas and load forecasts used in each utility's respective IRP avoided cost methodology annually on October 15.

Commission Findings: The Commission finds that the utilities' joint recommendation to update natural gas and load forecasts for each utility's IRP Methodology on October 15 of each year is reasonable. Therefore, updates to each utility's natural gas price forecast used in the SAR methodology shall be based on the EIA gas forecast and shall occur annually on June 1 or within 30 days of the final release of the EIA Annual Energy Outlook, whichever is later. Further, updates to gas and load forecasts used in the IRP methodologies shall occur annually on October 15.

CANAL DROP HYDRO PROJECTS

The Commission's final Order No. 32697, Attachment A defines "canal drop hydro" as "a generation facility which produces a 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." The Renewable Energy Coalition requested clarification of this definition and suggested an alternative classification. Because the definition of canal drop hydro was not fully explored at hearing, the Commission allowed discovery, comments and reply on the issue.

The Renewable Energy Coalition proposed that canal drop hydro projects be redefined as "irrigation related hydro projects" and include any generation facility "which produces a majority of its generation during the irrigation season and conveys or impounds water primarily intended for irrigation." Petition for Clarification at 4. The Coalition explained that its definition justified a higher avoided cost rate based on the correlation between the generation delivered and the utility's system peak, and not the physical features of the water delivery system. Comments at 1.

Idaho Power proposed that the Commission adopt changes to the definition of canal drop hydro that would base the definition on a hydro project's ability to deliver energy during peak summer load. Comments at 2. Idaho Power proposed the following definition:

> A "canal drop hydro project" is defined as a generation facility which produces 55% of its generation during the months of June, July, and August and is located on a man-made waterway that conveys water primarily intended for irrigation or that primarily conveys irrigation return flows.

Alternatively, Idaho Power recommended that, if the Commission wished to retain the entire irrigation season as part of the definition, the definition be modified as follows:

> A "canal drop hydro project" is defined as a generation facility which produces 96% of its generation during the months of April through October and is located on a man-made waterway that conveys water primarily intended for irrigation or that primarily conveys irrigation return flows.

Idaho Power also proposed that the provisions for implementation and compliance with the definition and qualification for the higher canal drop hydro rate be contained in the firm energy sales agreements between the utility and QFs. Comments at 7. Idaho Power recommended that compliance be verified each year at year-end to ensure that the project's generation is eligible to receive the higher avoided cost rate. If the project failed to deliver its energy during the proper time period, its rate would be changed to reflect the "hydro" published avoided cost rate structure. Any overpayment received by the project based on the "canal drop hydro" rates could be trued-up through energy payments made the following year.

Staff recommended replacing the term "canal drop hydro" with the term "seasonal hydro." Staff asserted that the location of the hydro project and use of the water is less important than whether the project reliably generates energy during the times when capacity is most valuable to the utility. Comments at 3. Staff proposed to define a seasonal hydro project as one that, over the last ten years, generated at least 90% of its average annual generation during the months of April through October. New hydro projects would be required to demonstrate compliance with the definition in the first year of operation with retroactive adjustment of rates if the project fails to comply. Comments at 3.

Commission Findings: After a thorough review of the underlying record in this case, the petitions for reconsideration, and comments and replies on reconsideration, the Commission adopts new terminology to classify hydro projects within the SAR methodology that better identifies the type of resource and timing of generation. We find that identifying the formerly classified "canal drop hydro" projects as "seasonal hydro" projects better describes the timing of the generation and the justification for higher avoided cost rates. We further find that a modification of the definition of what classifies as a "seasonal hydro" project is necessary.

We find that the appropriate and reasonable definition of a "seasonal hydro" project is a hydro generation facility that produces at least 55% of its annual generation during the months of June, July, and August. We agree with the proposition that the higher avoided cost rates available to these types of resources are based on the project's ability to deliver generation when the utility is most in need of energy. We find that the modified definition recognizes a utility's peak power consumption months and rewards projects that are able to deliver power during peak times when the utility would otherwise have to utilize an alternative resource to meet customer demand. Conversely, these projects do not produce energy that the utility is compelled to purchase during non-peak months. We find that requiring a QF to produce 55% of its generation during June, July and August when the utility is most in need of energy is a reasonable threshold to satisfy entitlement to higher avoided cost rates.

In order to ensure compliance with the requirement that 55% of a project's generation must be produced during the months of June, July and August, we find it just and reasonable for the utility to audit and verify the generation of a seasonal hydro project each year at year-end. If a project fails to deliver at least 55% of its energy during the proper time period, its rate will be changed to reflect the non-seasonal hydro published avoided cost rate structure. Any overpayment received by a project based on a mischaracterization as a seasonal hydro project should be trued-up through energy payments made to the project during the subsequent year.

These changes to resource type and eligibility only impact new and renewing projects. Current projects continue under their existing Agreements. As with any other change in eligibility or rates, new contracts and replacement contracts are subject to the eligibility criteria and rates in effect at the time that legal obligations are incurred.

RESOURCE SPECIFIC CAPACITY FACTORS

Idaho Power proposed the use of a different resource specific capacity factor for canal drop hydro projects that, it claims, is based upon actual data from projects on Idaho Power's system. Consequently, Idaho Power recommended use of a 67.1% capacity factor for canal drop hydro projects. Idaho Power further proposed a 92% capacity factor for projects falling within the "other" category based on the Northwest Power and Conservation Council's forced outage data. Comments at 8. Idaho Power argues that a 100% capacity factor for any resource is simply unreasonable. *Id.*

The Canal Companies support use of a 100% on-peak capacity factor for avoided cost calculations of canal drop hydro projects. The Canal Companies argue that, because canal drop hydro projects contribute capacity during the utility's summer peak season when the utility would otherwise have to purchase energy from another source to meet its load, such projects should be compensated for 100% of the capacity that a canal drop hydro project provides. The Canal Companies maintain that their position is supported by the testimony and exhibits of Commission Staff submitted in the underlying case. Comments at 2, n.1. The Canal Companies consider Idaho Power's capacity calculations for canal drop hydro projects to be flawed. The Canal Companies maintain that Idaho Power's calculations are based on inaccurate and imprecise data. The Coalition concurs with and adopts the position of the Canal Companies regarding resource specific capacity factors.

Commission Staff considered 20 years of Idaho Power data in order to identify the day and hour of Idaho Power's summer and winter peak. Comments at 5. After a detailed analysis of the approach used by Idaho Power to arrive at resource specific capacity factors and the compilation of its own research and discovery material, Staff calculated an annual capacity factor for seasonal hydro projects (aka canal drop hydro) at 32%. Staff further recommended that non-seasonal hydro projects be assigned an annual capacity factor of 50% and "other" projects be assigned an annual capacity factor of 89%.

On reply, Idaho Power concurred with Staff's analysis concerning the timing of summer peak hours. Reply at 4. Idaho Power further stated that it believes "that Staff's analysis addressed any deficiencies identified by other parties." Reply at 4. Idaho Power found Staff's recommended peak hour and annual capacity factors reasonable given Idaho Power's proposed definitional change for seasonal hydro projects. Reply at 5.

The Canal Companies acknowledged the "sound analysis undertaken by Staff" but disagreed with Staff's recommended on-peak capacity value. Reply at 4. Specifically, the Canal Companies disagreed with Staff's implicit assumption that the "avoided resource can and does provide on-peak capacity 100% of the time." Reply at 3. The Canal Companies also disputed Staff's use of a 90th percentile capacity (or exceedence) factor. Reply at 5.

Commission Findings: Based not only on the detailed analysis performed with historical data, but also the acknowledgement of Idaho Power and the Canal Companies that Staff's recommendations were based on a "sound analysis" that produced "reasonable" results, the Commission finds that Staff's approach provides a fair, just and reasonable basis for computing both peak hour and annual capacity factors. The Commission further finds that it is just and reasonable to use a 90th percentile capacity factor in peak hour capacity factor calculations. If a QF is to be awarded payment for providing capacity, then the utility must be assured that the planned-on capacity will be available the vast majority of the time. Using a 90th percentile capacity factor minimizes the risk that planned-on capacity is not available.

The Commission also finds merit in the Canal Companies assertion "that the avoided resource cannot provide 100% on-peak deliveries 100% of the time." Reply at 3. Consequently, the Commission finds that a 92% capacity factor for the SAR, which contemplates an 8% forced outage rate for baseload resources (as identified in the Northwest Power and Conservation Council's 6th Power Plan), is just and reasonable.

Utilizing (1) a 92% capacity factor for the avoided resource and (2) the updated definition of a seasonal hydro project results in the following annual and peak hour capacity factors:[1]

	Annual capacity factor	Peak hour capacity factors	
		Summer peak	Winter Peak
Seasonal hydro projects	33%	78%	0%
Non-seasonal hydro projects	46%	65%	25%
"Other" projects	89%	93%	93%

The change in capacity factors for seasonal hydro, non-seasonal hydro and "other" projects has no impact on these factors for wind and solar projects.

To be clear, these changes only impact new and renewing projects. Current projects continue under their existing agreements. As with any other change in eligibility or rates, new contracts and replacement contracts are subject to the eligibility criteria and rates in effect at the time that legal obligations are incurred.

OWNERSHIP OF RENEWABLE ENERGY CREDITS (RECs)

RECs (also known as environmental attributes, green tags, or renewable trading certificates) typically represent the environmental attributes associated with one megawatt-hour (MWh) of electricity generated from an eligible renewable energy facility. RECs may be created at renewable generating facilities operated by utilities, exempt wholesale generators (EWGs), non-PURPA generators, or PURPA qualifying facilities ("QFs"). Order No. 32697 at 37. The Commission's investigation in this case focused on REC transactions between QFs and Idaho public utilities. Before addressing the issues on reconsideration, it is helpful to briefly review the relevant regulatory landscape and the relationship between PURPA, renewable portfolio standards ("RPS"), and RECs.

A. Background

1. PURPA. Congress passed PURPA in 1978 in response to a national energy crisis. Its purpose was to lessen the country's dependence on foreign oil; encourage the development of renewable energy technologies; and control consumer costs. *FERC v. Mississippi*, 456 U.S. 472,

[1] Avoided cost rate tables for seasonal hydro, non-seasonal hydro and "other" based on these factors are attached.

745, 46, 102 S.Ct. 2126, 2130 (1982). To encourage the development of renewable generating facilities, Section 210 of PURPA requires electric utilities to purchase the power produced by co-generators or small power producers that are determined to be eligible qualifying facilities (QFs) under PURPA. 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a). This mandatory purchase requirement is often referred to as the "must purchase" provision of PURPA. *FERC v. Mississippi*, 456 U.S. at 751, 102 S.Ct. at 2133; Order Nos. 32697 at 7, 32580 at 3.

2. Renewable Portfolio Standards (RPSs). A RPS typically requires an electric utility to generate or purchase a certain percentage of its annual electric generation (its "portfolio") from designated energy resources, or alternatively, meet its RPS obligation by the purchase of unbundled RECs from renewable sources. *Alliance to Protect Nantucket Sound v. Dept. of Public Utilities*, 959 N.E.2d 413, 419 n.7 (Mass. 2011); Order No. 32002. The creation of RPS programs by the states occurred well after PURPA was enacted in 1978; RPS programs have generally been adopted since about 1995. *Steven Ferrey, et al.* "Fire and Ice: World Renewable Energy and Carbon Control Mechanisms Confront Constitutional Barriers," 20 Duke Env'lL. & Policy F. 125, (Winter 2010 (hereinafter "*Ferrey*")). In other words, RECs did not exist and were not contemplated when PURPA was enacted in 1978. Order No. 32697 at 37 *citing American Ref-Fuel Co.*, 105 FERC 61,005 at ¶ 4 (2003) *rehr'g denied*, 107 FERC 61,016 (2004) *dismissed sub nom. for lack of jurisdiction, Xcel Energy Services v. FERC*, 407 F.3d 1242 (D.C.Cir. 2005); Order No. 29480 at 3. As FERC noted in *American Ref-Fuel*, adoption of RPSs "are premised on promoting policy goals such as improved air and water quality, reduction of greenhouse gas emissions, broader fuel diversity, enhanced energy security, and hedging against the price volatility of fossil fuels." Order No. 32580 at 4 *citing American Ref-Fuel Co.*, 105 FERC 61,005 at ¶ 4; *see also* Order No. 32697 at 37. Thus, PURPA and RPS programs were created for different reasons. Order No. 32697 at 37.

As the Commission noted in its final Order No. 32697:

> 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*,
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>> 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, <u>RECs are inventions of state property law whereby the renewable energy attributes are</u>

"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 [61,004] 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. (Emphasis added.)

Order No. 32697 at 37-38 (emphasis as indicated).

In its prior final Order, the Commission noted that the parties agreed the Idaho Legislature has not implemented a RPS program nor has it enacted any statute addressing the ownership or allocation of RECs. The Commission observed that it has stated on several previous occasions that 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. 32697 at 38 *citing* Order Nos. 32580 at 9, 32480, 29577, 29630.

B. Prior Order No. 32697

1. Jurisdiction. In its prior Order, the Commission first took up the issue of whether it has subject matter jurisdiction over RECs. Although the Commission recognized it is a creature of statute and normally its jurisdiction is dependent upon statutory authority "once jurisdiction is clear, the Commission is allowed all power that is either expressly granted by the statute[s] or which may be fairly implied" to carry out its responsibilities. *Idaho State Homebuilders v. Washington Water Power Co.*, 107 Idaho 415, 418, 690 P.2d 350, 353 (1984). The Commission found that it has jurisdiction to decide the REC issue for three primary reasons. *Id.* at 43-45.

First, the Commission noted it was well settled that it has been granted authority to review QF contracts and resolve disputes between QFs and electric utilities. Order No. 32697 *citing A.W. Brown v. Idaho Power Co.*, 121 Idaho 812, 816, 828 P.2d 814, 845 (1992); *Empire Lumber Co. v. Washington Water Power Co.*, 114 Idaho 191, 755 P.2d 1229 (1988); *Afton*

Energy v. Idaho Power Co. ("Afton I/III"), 107 Idaho 781, 693 P.2d 427 (1984); *Idaho Code* § 61-612. The Commission found that the "disposition of RECs is now a term that is found in most, if not all, PURPA contracts." Order No. 32697 at 44. The Commission further declared that since 1980, it has required that all PURPA contracts be submitted to the Commission for its approval. *Id. citing* Order No. 15746, 38 P.U.R. 4th 352 (Idaho 1980); Order No. 29632 at 7; *Rosebud I*, 128 Idaho at 620, 917 P.2d at 778; *Rosebud II*, 128 Idaho at 628, 917 P.2d at 785. Likewise, *Idaho Code* §§ 61-502 and 61-503 authorizes the Commission to review and investigate contracts with utilities that affect utility rates and charges. Order No. 32697 at 44.

Second, the Commission recognized in *A.W. Brown*, that the Idaho 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. . . ." Order No. 32697 at 44 *citing* 121 Idaho at 819, 828 P.2d at 848. In rejecting the QF's argument, the Court held that "the Commission 'has jurisdiction to hear complaints against utilities alleging violation of any provision of law. . . .'" *Id.* The Commission also noted that the Court in *Empire Lumber*, declared the Commission is "granted authority by the Idaho statutes to, and is the appropriate forum to resolve" PURPA contract issues. Order No. 32697 at 44 *citing* 114 Idaho at 192, 755 P.2d at 1230.

Finally, the Commission found that it had authority to decide the REC issue because RECs directly affect utility rates and the disposition of RECs is a common term contained in most if not all PURPA agreements. Order No. 32697 at 44. The Commission observed that utilities recover the cost of purchasing QF power initially through the annual Power Cost Adjustment (PCA) mechanisms for Idaho Power and Avista, and in the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain. *Id. citing* Tr. at 392, 1107. The Commission found that the revenue from the sale of RECs directly offsets the avoided cost rates that utilities must pay QFs for power in PCA rates and base rates. *Id.* As the Supreme Court noted in *Washington Water Power Co. v. Kootenai Environmental Alliance*, 99 Idaho 875, 880, 591 P.2d 122, 127 (1979), *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." Order No. 32607 at 44.

2. Disposition of RECs. Despite the disagreement among the parties regarding the disposition of RECs, the Commission noted there were several issues which were not in dispute. First, all the parties agree that PURPA does not control RECs – RECs are controlled by the

states. In other words, RECs exist outside the confines of PURPA. *Id.* at 45. Second, the Commission found there was agreement among the parties that no Idaho law implements a renewable portfolio standard (RPS) program or addresses the disposition of RECs. *Id. citing* Order Nos. 32580, 29480 at 9. Finally, the Commission stated that the parties agree that Idaho's avoided cost rates do not compensate QFs for RECs. *Id. citing* Order No. 32580 at 3 *quoting Morgantown Energy Associates*, 139 FERC 61,066 at ¶ 47 (2012); *see also California PUC*, 133 FERC 61,059 at ¶ 31 n.62 (2010).

The Commission went on to describe RECs as intangible assets. "But for the 'must purchase' provision of PURPA, RECs would not exist or be created for a PURPA project." *Id.* at 45. RECs are not tangible and do not "exist" until the renewable QF project produces a MW of power. "RECs are non-physical assets which exist only in connection with something else, i.e., the purchase of renewable power under PURPA." Order No. 32580 at 10 *citing* Black's Law Dictionary at 808 (6^{th} ed. 1990). There is no REC without the generation of renewable power. Order No. 32697 at 45-46 (footnote omitted).

Absent an agreement between the parties in a PURPA contract to do otherwise, the Commission found it was reasonable to equally apportion RECs between the utility and QF when the contract is based upon rates derived through the IRP Methodology. *Id.* at 46.[2] "Because both the utility and 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 RECs by 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." *Id.* The Commission observed that equally splitting RECs between the utility and the QF has been approved in several recent Orders. *Id. citing* Order Nos. 32419, 32451, 32384, 32294, and 32125.

The Commission also found that dividing REC ownership equally between the utility and the QF is in the public interest. Equally dividing RECs under the IRP Methodology provides an additional revenue stream to QF developers, thereby encouraging the development of renewable generation. "This promotes the underlying purpose of PURPA." *Id.* at 47 *citing Rosebud II*, 128 Idaho at 627, 917 P.2d at 784. On the other hand, a utility's sale of RECs produces revenue which directly offsets the cost of purchasing PURPA power from the QF and

[2] For PURPA contracts using the surrogate avoided resource (SAR) methodology based on a natural gas-fired generating resource, the Commission allocated the RECs to the QF because a natural gas resource produces no RECs. Order No. 32697 at 46.

provides a tangible benefit to ratepayers. *Id.* at 46 *citing* Tr. at 573, 1192, 1193-94; Order No. 32002. In other words, both the QF and the utility (including its ratepayers) share the benefits of REC ownership. *Id.* at 47.

C. Reconsideration Issues

1. Jurisdiction. In its Petition for Reconsideration, the Idaho Conservation League (ICL) renews its argument that the Commission does not have subject matter jurisdiction to decide the REC issue. ICL generally presents two arguments. First, ICL asserts that Order No. 32697 oversteps the Commission's jurisdiction by presuming that RECs have been "dedicated to public use." ICL Petition at 1-2. Relying on the early case of *Idaho PUC v. Natatorium*, 36 Idaho 287, 215 P. 533 (1922), ICL maintains that only QFs that "include RECs in [their PURPA] contracts are making an unequivocal dedication of [RECs] to public use." *Id.* at 2. Conversely, QFs that do not include RECs in their contracts are not dedicating RECs to public use, or in other words, not subjecting RECs to the Commission's jurisdiction. *Id.*

Second, although the Commission recognizes that RECs are subject to state law, ICL asserts the Commission did not determine who owns RECs in the first instance. ICL generally argues that RECs "are an asset created through the efforts of QF developers," and the QF's "property interest [in RECs] arise[s] spontaneously" and vests in the QF. *Id.* ICL notes that the Court in a 1911 case held that a person who collects rain and snow melt on his property has created a private property right in such water and the water is "not subject to the dedication to public use of water." *Id. citing King v. Chamberlin*, 20 Idaho 504, 118 P. 1099 (1911). The Commission should not presume that RECs are dedicated to public use and subject to the Commission's jurisdiction.

Idaho Power filed a timely answer asserting that the Commission "clearly has subject matter jurisdiction to make determinations regarding the ownership of RECs in the PPAs. Answer and Cross-Petition at 17. Idaho Power argued that its previous legal brief confirms that State Commissions, the U.S. Court of Appeals for the Second Circuit, and the Appellate Courts of Connecticut, New Jersey, Pennsylvania, and West Virginia "all agree that ownership of RECs is decided by States even in the context of a PURPA power sales [Agreement]." *Id.*

Commission Findings: After reviewing the underlying record, the previously filed legal briefs, and the points raised in ICL's reconsideration Petition, we affirm our initial decision made in Order No. 32697 that the Commission has subject matter jurisdiction to decide the REC dispute in PURPA contracts. In addition to those reasons set out in our prior Order, the Commission finds that there are several other points supporting our jurisdiction.

At the outset, we find that our authority over PURPA contracts does not arise solely from State statutes. In the context of a PURPA contract, the Idaho Supreme Court has declared that PURPA imposes "requirement on state regulatory authorities in excess of their duties under state law." *Afton I/III*, 107 Idaho at 785, 693 P.2d at 431 (emphasis added). The Court declared that the United States Supreme Court in *FERC v. Mississippi* "stated that through PURPA the federal government attempted to use state regulatory machinery to advance federal goals. The Court held as constitutional the requirements of Section 210 which 'has the States enforce standards promulgated by FERC.' Thus, it is clear that PURPA was intended to confer upon state regulatory commissions responsibilities not conferred under state law." *Id. quoting FERC v. Mississippi*, 456 U.S. at 759, 102 S.Ct. at 2137 (emphasis added).

In *Empire Lumber*, the Idaho Supreme Court observed that the Commission's PURPA responsibilities can be accomplished in a manner subsumed or consistent with its statutory authority over public utilities. The "Commission is the agency authorized . . . to supervise and regulate electric utilities, and has ratemaking authority over such utilities. The Commission as part of its statutory duties determines reasonable rates and investigates and reviews contracts. The Commission also has jurisdiction to hear complaints against utilities alleging violation of any provision of law or of any order . . . of the Commission." *Empire Lumber*, 114 Idaho at 192, 755 P.2d at 1230 (internal citations omitted and emphasis added) *citing Idaho Code* §§ 61-129, 61-501, 61-502, 61-503, 61-612. As the United States Supreme Court held in *FERC v. Mississippi*, the state utility commission "can satisfy [PURPA] § 210's requirements simply by opening its doors to [PURPA] claimants. . . . Congress determined that the federal rights granted by PURPA can appropriately be enforced through state adjudicatory machinery," i.e., the Idaho Commission. 456 U.S. at 760, 102 S.Ct. at 2137; *Afton I/III*, 107 Idaho at 789, 693 P.2d at 435. Although RECs are not controlled by PURPA, the disposition of RECs is addressed in PURPA contracts with other necessary terms and conditions. *See Empire Lumber*, 114 Idaho at 192, 755 P.2d at 1230.

We find ICL's reliance upon the *Natatorium* case and whether QFs have dedicated RECs "to public use" to be misplaced for two primary reasons. First, ICL infers that if PURPA agreements do not contain references to RECs, then RECs are not dedicated to "the public use."

However, as the Commission previously found, most if not all PURPA contracts do address RECs. Order No. 32697 at 44. Second, in *Idaho PUC v. Natatorium*, the issue was whether the Natatorium Company was a public utility subject to the Commission's regulatory jurisdiction under *Idaho Code* §§ 61-125, 61-129. The Court in *Natatorium* examined whether the company devoted its physical assets to the "public use" and supplied water to customers. In this case we are not examining whether a QF is operating as a public utility. More specifically, the sale of RECs by itself does not make the QF a utility. *Idaho Code* § 61-129. In fact, PURPA exempts QFs from most but not all state utility regulation. 16 U.S.C. § 824a-3(b), (e); 18 C.F.R. § 292.602(c)(1)(i, ii); *Rosebud I*, 128 Idaho 614, 917 P.2d at 771; *Afton I/III*, 107 Idaho at 787-88, 693 P.2d at 433-34. What is at issue here is the appropriate disposition of RECs. Consequently, we find the test for determining whether a company is a public utility is not applicable or controlling over the issue of REC ownership.[3]

We also find ICL's reliance on *King v. Chamberlin*, 20 Idaho at 504, 118 P. at 1099 is misplaced. ICL Petition at 2. In *King*, the Court ruled that a person who collects rain and snow melt on his property holds the resulting water as private property. ICL argues that, like captured water, "RECs are an asset created through the efforts of QF developers. . . ." *Id.* However, *King* too is distinguishable for several reasons. First, a person who collects water from rain and snow on his property has tangible property, i.e., the water. Here, RECs are intangible property. As we found in our prior final Order, but for the "must purchase" requirement of PURPA, the generation of renewable power and the resulting RECs would not exist or be created. RECs are non-physical assets which exist only in connection with something else, i.e., the generation of renewable power. Order No. 32697 at 45-46 *citing* Order No. 32580 at 10; Black's Law Dictionary at 808 (6th ed. 1990). With PURPA contracts, there is the added compulsion of the utility's "must purchase" obligation. When a QF utilizes PURPA to compel a utility to purchase its renewable power, the RECs would not be created but for the "must purchase" requirement imposed on the utility.

Second, a person capturing snow or rain for his own use is not a water utility corporation. *Idaho Code* §§ 61-125, 61-129. Third, the disposition of RECs is now a common

[3] The facts of *Natatorium* are also distinguishable. The case was decided on stipulated facts. The parties stipulated that "Surplus hot water has never been offered for sale to any person [and] the said natural hot water was strictly a private and not a public use. . . ." *Stoehr v. Natatorium*, 34 Idaho 217, 220, 200 P. 132, 133 (1921); *Idaho PUC v. Natatorium*, 36 Idaho at 334, 211 P. at 547 (Dunn,J., dissenting).

provision in Idaho PURPA contracts. Besides having jurisdiction over contracts that affect utility rates under *Idaho Code* §§ 61-502 and 61-503, the Commission has jurisdiction to approve PURPA contracts, including any REC provisions contained in the agreements. *A.W. Brown*, 121 Idaho at 816, 828 P.2d at 846; *Empire Lumber*, 114 Idaho at 192, 755 P.2d at 1229.

Finally, our Supreme Court also recognized that the Commission may resolve disputes between QFs and electric utilities. Order No. 32697 at 44 and cases noted therein. There can be no disagreement that the parties here dispute the appropriate disposition and ownership of RECs as part of this generic PURPA investigation. Given these reasons, we conclude we have jurisdiction to decide the REC issue. Having found jurisdiction, we now turn to the ownership of RECs.

2. <u>Ownership of RECs</u>. ICL, Renewable Northwest Project (RNP), and Simplot/Clearwater Paper all seek reconsideration regarding the Commission's decision that RECs under the IRP methodology belong equally to both the QF developer and the utility. ICL asserted that the Commission's decision to apportion RECs equally between the QF and the utility is not adequately explained nor supported by substantial and competent evidence. ICL Petition at 3. Although ICL conceded the utilities have renewable resources in their generation portfolio, this fact does not support allocating a portion of RECs to utilities. *Id.*

ICL agreed with the Commission's decision that RECs should belong to the QF under the SAR Methodology. Likewise, Simplot/Clearwater does not request reconsideration of the Commission's decision that QFs retain RECs in contracts with SAR-based rates. Petition at 4 n.2. RNP also does not challenge the Commission's REC decision for SAR-based QF contracts. RNP at 2-3.

Simplot/Clearwater challenged the Commission's determination that the RECs belong equally to the utility and the QF when rates are derived through the IRP Methodology. They argued that the Commission's decision violates PURPA by: (1) assuming QFs are compensated for RECs in the avoided cost rates; (2) discriminating against QFs versus non-QFs; and (3) discriminating against large QFs by denying them their full avoided cost. Petition at 11. For its part, RNP argued that Idaho common law vests ownership of RECs with the QF. Petition at 3. RNP also insisted that the Commission has not laid out a rational basis for evenly dividing RECs between the utility and the QF. *Id.* at 3-4. Finally, RNP asserted that the Order unreasonably discriminates against wind and solar QFs based upon generating technology with no discernible rationale. *Id.*

Idaho Power filed a timely answer to the three Petitions for Reconsideration and submitted a Cross-Petition for Reconsideration. Idaho Power urged the Commission to deny reconsideration on the REC issues. Idaho Power invited the Commission to review its arguments and citations to authority in the REC portion of its legal brief. Answer at 19; *see* IPC Legal Brief at 79-97. Just as ICL, RNP and Simplot/Clearwater asserted that the QFs are owners of RECs, Idaho Power advocated in its Cross-Petition "that the utilit[ies] be determined the owners of RECs in the initial instance." *Id.*

In Order No. 32737, the Commission granted reconsideration on the issue of RECs. The Commission found that further evidence is not necessary because the primary issues are questions of law. Order No. 32737 at 2; Rule 332. Consequently, the Commission did not seek further legal briefing because the REC issue "has already been the subject of extensive legal briefing by the parties in this case." *Id.* at 2-3. In addition, the reconsideration parties do not raise new legal issues for us to consider. Consequently, the Commission declared that it would reconsider its REC decision based upon the existing record and previously filed legal arguments.

Commission Findings: We begin our reconsideration of the REC issue by reiterating that ownership of RECs is determined by the States. RECs exist outside the confines of PURPA. States have the power to determine who owns the RECs in the initial instance. Order No. 32697 at 37-38, 47; *American Ref-Fuel*, 105 FERC 61,004; *Wheelabrator Lisbon v. Connecticut Dept. of Pub. Util. Control*, 532 F.3d 183, 186 (2d Cir. 2008); *Wheelabrator Lisbon v. Connecticut Dept. of Pub. Util. Control*, 526 F.Supp.2d, 295, 305 (Conn. 2006); *In Re Ownership of Renewable Energy Certificates*, 913 A.2d 825, 830-31 (App.N.J. 2007); *Wheelabrator Lisbon v. Dept. of Pub. Util. Control*, 931 A.2d 159, 173-74 (Conn. 2007); *Idaho Wind Partners*, 136 FERC 61,174 at n.10 (2011). Moreover, "RECs are separate commodities . . . and [are] not part of the avoided cost calculation." *California PUC*, 133 FERC 61,059 at ¶ 31 n.62 (2010); Order Nos. 32580 at 8, 32697 at 45.

The Idaho Supreme Court has recognized that PURPA contracts represent a "special type of contract." *Afton I/III*, 107 Idaho at 793, 693 P.2d at 439; *Afton Energy v. Idaho Power Co. ("Afton V")*, 114 Idaho 852, 854, 761 P.2d 1204, 1206 (1988). In our view, what makes them a "special type of contract" is the fact that federal law compels utilities to purchase power without arms-length bargaining and without regard to whether the utility needs the power. *Wheelabrator Lisbon v. Dept. of Public Util. Control*, 921 A.2d 159, 174 (Conn. 2007).

The Idaho Supreme Court has declared that "Freedom of contract is a fundamental concept underlying the law of contract and is an essential element of the free enterprise system." *Morrison v. Northwest Nazarene University*, 152 Idaho 660, 661, 273 P.3d 1253, 1254 (2012) *quoting Rawlings v. Layne & Bowles Pump Co.*, 93 Idaho 496, 499, 465 P.2d 107, 110 (1970); Order No. 32580 at 10. However, the utility as a party to a PURPA contract is not wholly free to bargain because PURPA compels utilities to purchase the power output produced by QFs. PURPA compels the utility to purchase power whether it needs the power to serve load or not. Even if QF power replaces power the utility would otherwise generate, ratepayers are ultimately paying for both the capital assets of the utility's baseload generating plant in rates and the QF power. While PURPA compels the underlying purchase of eligible renewable power, the RECs are intangible assets which arise only because of their association with the generation of renewable power under the "must purchase" provision. In other words, but for the must purchase provision of PURPA there is no requirement to purchase – no PPA – and RECs would not exist or be created. Order No. 32580 at 10.

The question of REC ownership hinges upon which party has a property interest in RECs. Whether a party has a compensable property interest in RECs presents "a question of law based upon factual underpinnings." *See Mohlen v. United States*, 74 F.Cl. 656, 660 (2006) *quoting Walcek v. United States*, 303 F.3d 1349, 1354 (Fed.Cir.) *citing Wyatt v. United States*, 271 F.3d 1090, 1096 (Fed.Cir. 2001), *cert denied sub nom. E. Minerals Int'l v. United States*, 535 U.S. 1077, 122 S.Ct. 1960 (2002).

The Supreme Court of Connecticut's *Wheelabrator Lisbon v. Dept. of Pub. Util. Control* decision is instructive in analyzing the ownership issues surrounding RECs. In that case, the Court affirmed the state regulatory commission's decision that the ownership of RECs under existing PURPA agreements that do not mention RECs vests with the utility. The Connecticut Supreme Court addressed several factors in its analysis. First, it noted that PURPA's must purchase provision compels utilities to purchase power that it would not otherwise be obligated to purchase but for PURPA. *Wheelabrator*, 931 A.2d at 174. Second, the RECs are "inexplicably tied to the [QF's] production of electricity." *Id.* In other words, but for the PURPA requirement that utilities purchase the power generated by QFs, RECs would not be created nor would they be contemplated within the context of a PURPA contract. Moreover, the disposition of RECs has become a standard provision in PURPA contracts. Third, PURPA requires that the utility must purchase the power without any demonstration that the utility needs the power. *Id.* at 175. Finally, providing all the RECs to the QF would result in a windfall to them. *Id.* at 174-75.

The Court went on to declare that

> the term [REC] "unbundling" itself implies that the renewable attribute of the energy generated by renewable energy resources is an inherent attribute of the energy, and, therefore, the creation and state recognition of the certificates did not result in an entirely new commodity but in the splitting of a pre-existing commodity, i.e., "electricity," that the utility had contracted to purchase. It was reasonable, therefore, for the [state regulatory agency] to conclude that the word "electricity," as used in [the state statute] and the 1991 agreement meant renewable energy. In other words, the term "electricity" necessarily included the renewable attribute that later was "unbundled" from the energy and represented by the certificates. Accordingly, we conclude that the Department reasonably determined that the certificates were owned by the utility.

Wheelabrator, 931 A.2d at 176 (footnote omitted). *See also* Order No. 32697 at 38-39 *citing* Tr. at 223-25.

On the other hand, we recognize that QFs must first generate the power before a REC is created. QFs must build their facilities and interconnect with the utility purchasing the generated power under the PURPA contract. Second, providing all the RECs to the utility would result in a windfall to the utility. *Wheelabrator*, 931 A.2d at 175 n.24. We have also noted that the secondary source of REC income for QFs further encourages the development of renewable resources consistent with the goals of PURPA and intent of this Commission.

We find these utility and QF property interest factors applicable in considering the ownership of RECs. We find that Idaho common law does not vest RECs exclusively in either the QF or the utility. We find especially important the fact that PURPA compels the purchase and that utilities must purchase QF power whether needed or not. These facts are balanced against the QF's investment in the renewable facility and the Congressional goal of promoting renewables. Although the Connecticut Court and other courts have concluded that RECs belong to the utility, we affirm our previous decision that RECs under the IRP methodology should be equally divided between the QF and the utility. After considering the factual underpinnings of how RECs are created as set out above, we find that it is just, reasonable and in the public interest that the ownership (i.e., the property interest) of RECs should be vested equally in both the utility and the QF. We conclude that RECs under the IRP methodology should be equally shared by the parties while still allowing for some contractual flexibility.

Based upon the factual underpinnings above, we find there is substantial and competent evidence that the QFs do not have an exclusive cognizable property interest in RECs. *See also Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1001, 104 S.Ct. 2862, 2871 (1984) ("Property interests . . . are not created by the Constitution. Rather they are created and their dimensions are defined by existing rules or understandings that stem from an independent source such as state law.").

3. Substantial and Competent Evidence. The three parties challenging our REC decision allege there is not substantial and competent evidence supporting the Commission's decision that the ownership of RECs under the IRP methodology resides equally in both the utility and QF. We disagree for several reasons.

Commission Findings: First, we note there is compelling authority from other states that RECs belong to the utility in their entirety. While we do not find that RECs belong entirely to utilities, several states have adopted this position – just like other states that have adopted RPS and REC programs. As the appellate court in New Jersey noted, nine states have ruled that RECs "are the property of the purchasing utility rather than the producer" in contracts that do not reference RECs or in PURPA contracts that were entered into before the concept of RECs arose. *In Re Ownership of Renewable Energy Certificates*, 913 A.2d 825, 828 (N.J.App. 2007) *citing Edward A. Holt et al.*, "Who Owns Renewable Energy Certificates? An Exploration of Policy Options and Practice," at 14 (2006).[4] Tr. at 222-25; Wyoming Order No. 12750 at ¶ 63; *Ferrey* at 145-46. Second, allocating RECs equally to both parties mitigates arguments that RECs apportioned to either party in their entirety results in a windfall. As we have noted in this and past Orders, RECs provide an incentive and encouragement for the development of QF facilities and also help to offset the expense of renewables when retained by the utility for the benefit of ratepayers – all of which are recognized as goals of PURPA. *Rosebud II*, 128 Idaho at 627, 917 P.2d at 784; Order No. 32697 at 47.

[4] Published by the Ernest Orlando Lawrence Berkley National Laboratory, available at: eetd.lbl.gov/ea/emp/reports/599965.pdf.

Third, we found in final Order No. 32697 that IRP-based rates are derived from the utility's actual resource portfolio which contains both renewable and non-renewable generating resources. Order No. 32697 at 46. Thus, IRP rates reflect the actual generation characteristics of the utility's generating resources, including renewable resources. According to the 2012 Idaho Energy Plan adopted by the Idaho Legislature on March 6, 2012, Avista's resource mix is reported to be 54% renewable (biomass and hydro); Idaho Power's resource mix is reported to be 54.6% renewable (hydro, wind, geothermal and biomass); and PacifiCorp non-carbon emitting resources are reported to be approximately 24% of its portfolio. Energy Plan at 29-30; HCR 34 (2012).[5] In addition, as "a stand-alone utility, PacifiCorp is second only to Mid-America Energy Company in ownership of wind generation. . . . At year-end 2010, PacifiCorp had more than 1,000 megawatts of owned wind generation capacity and long-term purchase agreements for more than 600 megawatts from wind projects owned by others." *Id.* at 29-31. Moreover, the Energy Plan reports that <u>Idaho dams produce</u> "in an average year <u>approximately half</u> of Idaho's 2010 <u>electricity consumption</u>." § 2.3.2 at p. 42 (emphasis added). More importantly, we have found based upon the property interest facts set out above, that it is reasonable and just to vest REC ownership equally between the QF and the utility. The resource mix in the IRP methodology further supports our decision that RECs belong equally to utilities and QFs. Consequently, we find that there is substantial and competent evidence supporting the Commission's decision to split RECs equally between utilities and QFs under the IRP methodology.

4. <u>Technology Distinction</u>. RNP and to some extent Simplot/Clearwater argued that vesting RECs equally between the QF and the utility "unreasonably penalizes wind and solar resources as compared to other technologies." RNP at 3. Because the eligibility cap for wind and solar is set at 100 kW, RNP argues that the Order in effect "assigns RECs from QFs sized 100 kW to 10 aMW to utilities only for wind and solar technologies." *Id.* at 4.

Commission Findings: RNP's argument misses the mark. First, our prior Order does not "assign RECs from [wind and solar] QFs sized 100 kW to 10 MW to utilities." *Id.* In fact, RECs for wind and solar QFs larger than 100 kW are equally divided between the utility

[5] ICL asked us to take official notice of Idaho Power's IRP. ICL Petition at 4 n.1. Without relying on the IRP for this Order, we noted that Idaho Power's 2011 IRP shows its 2010 supply-side resources were 48.4% hydro, 3.1% wind, .5% biomass, .5% waste, and 46.5% fossil fuel. Fig. 1.3. Under the projected 2030 fuel mix, fossil fuel resources are estimated to reduce to approximately 35% while hydro and other renewables increase to more than 63% (with the inclusion of .5% nuclear power). Fig. 1.4, Case No. IPC-E-11-11.

and the QF. Second, it appears the RNP's real argument is that the eligibility cap for the published avoided cost rates for wind and solar projects is set at 100 kW. That decision was made in an earlier case (GNR-E-11-01). In that case, the Commission found that it was appropriate to set the eligibility cap for the published SAR-based avoided cost rates at 100 kW for wind and solar QFs. Order No. 32697 at 3-4 *citing* Order No. 32262.

As we have noted in past Orders, PURPA and its implementing regulations require that the published/standard avoided cost rates be established and made available to QFs with design capacity of 100 kW or less. 18 C.F.R. § 292.304(c). Moreover, in establishing the eligibility criteria for a published avoided cost rate, the Commission may differentiate among QFs using various technologies. 18 C.F.R. § 292.304(c)(3). Order No. 32262 at 1. Over the years, the eligibility for standard rates has ranged from the minimum requirement of 100 kW or less to projects as large as 10 MW. *Id.* at 8. In Phase II of our generic PURPA investigation, we set the eligibility cap for wind and solar QF projects at 100 kW. *Id.* at 8-9. No party (including RNP) sought reconsideration of the Commission's eligibility cap Order No. 32262 (Case No. GNR-E-11-01). Thus, wind and solar projects larger than 100 kW are entitled to PURPA contracts at avoided cost rates calculated using the IRP methodology. Order No. 32262 at 8.

Third, as we stated in Order No. 32580, FERC regulations provide that the calculation of avoided costs may differentiate among QFs "using various technologies on the basis of the supply characteristics of the different technologies." Order No. 32580 at 8 *quoting* 18 C.F.R. § 292.304(c)(3)(ii). In Order No. 32176, we distinguished wind and solar from other QF resources such as hydro, biomass, cogeneration, geothermal and water-to-energy. We found in Phase I and affirmed in Phase II of this generic PURPA investigation that:

> Wind and solar resources present unique characteristics that differentiate them from other PURPA QFs. Wind and solar generation, integration, capacity and ability to disaggregate provide a basis for distinguishing the eligibility cap for wind and solar from other resources. Furthermore, these intermittent resources must be "firmed" by ancillary services to assure system reliability.

Order Nos. 3176 at 9; 32212 at 15-16; 32262 (affirming the 100 kW eligibility cap for wind and solar). "Wind and solar projects larger than 100 kW continue to be entitled to PURPA contracts at avoided cost rates calculated using the IRP Methodology." Order No. 32262 at 8. Moreover, the disposition of RECs is not dependent on the type of renewable resource. The disposition of RECs relies on the methodology used in calculating a QF's avoided cost.

Finally, as set out above we find that REC ownership vests in both the QF and the utility. The Commission has the authority to differentiate rates based on specific characteristics of different technologies. The States (this Commission) further retain the authority to assign ownership of RECs. This Commission assigns REC ownership based on the generating resource used to calculate the rate. SAR rates, now based on a natural gas resource, assign RECs to the QF because an equivalent facility constructed by the utility would not generate RECs. Projects subject to the IRP rate methodology enjoy rates based on the actual renewable project being constructed whether constructed by the QF or the utility. Therefore, we find it equitable to split the RECs under these circumstances. Consequently, the Order does not unreasonably discriminate among generating technologies. Again, RECs are based on the acquired property right based upon the factors outlined above.

5. Taking. Simplot/Clearwater argue that the vesting of RECs equally in both the utility and the QF means that "QFs must cede half of their RECs for no additional payments." Petition at 16. They also insist that vesting REC ownership equally between the QF and the utility constitutes a taking of property without just compensation in violation of both the U.S. and Idaho Constitutions. *Id.* at 19. They characterize the allocation of RECs to utilities as a "gift" of 50% of the RECs, or a taking without just compensation. *Id.* at 20.

Commission Findings: Simplot/Clearwater's argument mischaracterized the Commission's Order No. 32697 and is off the mark. The Commission is not requiring QFs to give half their RECs to the utility. The Commission is finding that the utility and the QF, based upon the rationale set out above, equally share a property right in the RECs based on the renewable characteristics and how the avoided cost rate for such projects is derived. Consequently, we have not taken or impaired a QF's ability to sell its property interest in half the RECs. Order No. 32697 at 47. "As the Connecticut Supreme Court found in a similar case, the PUC's 'decision [to vest RECs in the utility] could not constitute an unconstitutional taking under the State's Constitution because no property owned by the [QF] has been taken." *Id. quoting Wheelabrator*, 931 A.2d at 177; *Wheelabrator Lisbon*, 526 F.Supp.2d at 307 (D.Conn. 2006) *affirmed*, 531 F.3d 183 (2d Cir. 2008). In other words, the QFs do not possesses a cognizable property interest in all of the RECs – only their half of the RECs. Thus, no taking has occurred.

Simplot/Clearwater point to the power purchase agreement regarding the Neal Hot Springs geothermal facility as an example of discrimination between a non-QF and a QF generator. However, this comparison is not appropriate as it compares dissimilar projects. As they acknowledge, the Neal geothermal facility <u>is not</u> a PURPA project. Order No. 31087 at 2. Consequently, the parties were at liberty to bargain and negotiate the various terms of their agreement including whether there would even be a contract. Moreover, our Order No. 32697 regarding the disposition of RECs is not inconsistent with PURPA because: (1) PURPA does not apply to the disposition of RECs; and (2) there is no assumption that IRP-based avoided cost rates compensate QFs for RECs. Indeed, we have been steadfast and clear in stating that avoided cost rates do not compensate QFs for RECs.

Another important point to remember is that this Order and the prior final Order No. 32697 do not affect any existing PURPA contracts. In addition, we further recognize that the parties have flexibility in negotiating the allocation of RECs. Parties may negotiate disposition of REC ownership. Order No. 32697 at 46.

6. <u>Dormant Commerce Clause</u>. Simplot/Clearwater also argued that the Commission's Order No. 32697 "directs the utilities to take title to an interstate commodity created by <u>*other states'*</u> RPS laws – RECs." Petition at 24. They further characterize the Order as unlawfully requiring "RECs to be processed in-state and then resold out-of-state by the Commission's chosen proprietors." *Id.* at 25.

Commission Findings: The Commerce Clause of the United States Constitution gives Congress the power to regulate commerce among the States. Art. I, § 8, Cl. 3. "The United States Supreme Court has consistently held that the Commerce Clause includes a 'further, negative command, known as the dormant Commerce Clause.'" *Alliance to Protect Nantucket*, 959 N.E.2d 413, 421 n.12 (2011) (citations omitted). The dormant Commerce Clause has been interpreted to prohibit "different treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter, as opposed to state law that regulates evenhandedly with only incidental effects on interstate commerce." *Id.* (internal punctuation and citations omitted). The crucial inquiry is whether the Commission's REC decision is basically a protectionist measure or can it fairly be viewed as a decision directed to legitimate state concerns, with only incidental effects on interstate commerce. *McBurney v. Young,* __ U.S. __, __S.Ct. __, 2013 WL 1788080, Slip Op. (April 29, 2013) *citing Philadelphia v. New Jersey*, 437 U.S. 617, 624, 98 S.Ct. 2531 (1978).

Contrary to Simplot/Clearwater's assertion, there is no different treatment between in-state and out-of-state economic interests – the ownership of RECs is for States to determine and our REC decision evenhandedly applies both to in-state utilities and QFs, and to out-of-state QFs selling to Idaho utilities.[6] *Wheelabrator*, 531 F.3d at 186; *American Ref-Fuel*, 105 FERC 61,004 at ¶ 23; *Idaho Wind Partners*, 136 FERC 61,174 at ¶ n.10. Our REC decision is not protectionist and is directed to a legitimate state interest – deciding REC ownership. In addition, Simplot/Clearwater has not adequately shown that vesting ownership of RECs under Idaho law equally to the QF and the utility has burdened interstate commerce. Utilities and QFs may sell their RECs to in-state or out-of-state entities. Moreover, out-of-state utilities may be subject to entirely different REC or RPS standards, unlike Idaho that has neither. Based on the foregoing, we find no dormant Commerce Clause violation.

"Insofar as RECs are state-created, different states can treat RECs differently." *American Ref-Fuel*, 107 FERC 61,016 at n.4. When a QF project derives its avoided cost rate based on the resource's renewable characteristics, the resource avoided by the utility is presumed to be a like resource – renewable. But for the "must purchase" obligation imposed by PURPA, the utility would be generating the energy – and creating RECs – with its own like resources. Under such circumstances, it is just and reasonable to equally apportion ownership of RECs between the QF and the utility.

CONCLUSION

The Idaho Public Utilities Commission has jurisdiction over electric utilities and the issues raised in 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 the implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided costs, to order electric utilities to enter into fixed-term obligations for the purchase of energy from qualified facilities (QFs) and to implement FERC rules. It is well-settled that the Commission has the authority to review contracts and resolve disputes between QFs and electric utilities. Thus, REC ownership – having been delegated to the

[6] Idaho QFs selling to out-of-state utilities is beyond the scope of our jurisdiction.

states and inextricably linked to PURPA generation – is a matter appropriately resolved by this Commission.

The Commission has reviewed the underlying record, including the petitions, responses, comments, and replies filed on reconsideration by the parties in this case. Based on the record, we find that the foregoing findings and conclusions are just and reasonable. We further find that the conclusions are supported by substantial and competent evidence.

ORDER

IT IS HEREBY ORDERED that gas and load forecasts used in IRP methodologies shall occur annually on October 15.

IT IS FURTHER ORDERED that new or renewing "canal drop hydro" projects be designated as "seasonal hydro" projects. A "seasonal hydro" project shall be defined as a hydro generating facility that produces at least 55% of its annual generation during the months of June, July and August.

IT IS FURTHER ORDERED that capacity factors for "seasonal hydro," "non-seasonal hydro," and "other" projects utilizing the SAR methodology be modified as more particularly described herein.

IT IS FURTHER ORDERED that RECs produced by projects utilizing the IRP Methodology be apportioned equally between the utility and the QF.

THIS IS A FINAL ORDER ON RECONSIDERATION. Any party aggrieved by this Order or other final or interlocutory Orders previously issued in this Case No. GNR-E-11-03 may appeal to the Supreme Court of Idaho pursuant to the Public Utilities Law and the Idaho Appellate Rules. See *Idaho Code* § 61-627.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 6th day of May 2013.

PAUL KJELLANDER, PRESIDENT

MACK A. REDFORD, COMMISSIONER

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

O:GNR-E-11-03_ks8_Final Reconsideration

AVISTA
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
May 6, 2013
$/MWh
New Contract

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	30.53	30.35	30.25	33.34	34.38	35.49	2012	30.53
2	30.45	30.30	31.73	33.84	34.91	36.12	2013	30.35
3	30.39	31.24	32.54	34.34	35.49	36.84	2014	30.25
4	31.04	31.93	33.19	34.89	36.15	43.93	2015	33.34
5	31.60	32.53	33.80	35.49	41.70	48.80	2016	34.38
6	32.12	33.10	34.43	40.00	45.88	52.58	2017	35.49
7	32.64	33.70	38.25	43.62	49.29	55.61	2018	36.81
8	33.18	36.95	41.43	46.68	52.14	58.09	2019	38.48
9	35.98	39.76	44.21	49.30	54.52	60.16	2020	69.05
10	38.46	42.26	46.62	51.54	56.54	61.99	2021	72.79
11	40.70	44.47	48.72	53.46	58.33	63.67	2022	76.90
12	42.71	46.41	50.54	55.19	59.99	65.20	2023	80.16
13	44.50	48.12	52.19	56.79	61.50	66.59	2024	82.50
14	46.09	49.67	53.73	58.25	62.87	67.88	2025	84.57
15	47.54	51.13	55.14	59.59	64.16	69.10	2026	87.28
16	48.91	52.47	56.43	60.84	65.36	70.26	2027	90.86
17	50.17	53.70	57.63	62.01	66.50	71.35	2028	93.66
18	51.33	54.85	58.77	63.12	67.58	72.43	2029	96.12
19	52.42	55.93	59.84	64.16	68.64	73.50	2030	99.22
20	53.45	56.96	60.85	65.19	69.67	74.49	2031	102.47
							2032	105.80
							2033	109.07
							2034	113.98
							2035	119.12
							2036	121.78
							2037	126.02

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 SEASONAL HYDRO PROJECTS
May 6, 2013
$/MWh
New Contract

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	30.53	30.35	30.25	33.34	34.38	35.49	2012	30.53
2	30.45	30.30	31.73	33.84	34.91	36.12	2013	30.35
3	30.39	31.24	32.54	34.34	35.49	36.84	2014	30.25
4	31.04	31.93	33.19	34.89	36.15	48.31	2015	33.34
5	31.60	32.53	33.80	35.49	45.05	55.83	2016	34.38
6	32.12	33.10	34.43	42.67	51.49	61.41	2017	35.49
7	32.64	33.70	40.43	48.21	56.54	65.77	2018	36.81
8	33.18	38.78	45.27	52.74	60.63	69.25	2019	38.48
9	37.54	43.02	49.35	56.51	63.99	72.12	2020	88.92
10	41.27	46.68	52.82	59.68	66.81	74.60	2021	92.95
11	44.54	49.84	55.78	62.37	69.27	76.83	2022	97.35
12	47.41	52.58	58.33	64.75	71.49	78.82	2023	100.91
13	49.93	54.97	60.61	66.91	73.49	80.62	2024	103.55
14	52.15	57.12	62.68	68.86	75.28	82.27	2025	105.93
15	54.16	59.08	64.56	70.62	76.94	83.80	2026	108.96
16	56.01	60.87	66.27	72.24	78.47	85.24	2027	112.85
17	57.70	62.51	67.84	73.75	79.91	86.59	2028	115.97
18	59.24	64.02	69.31	75.16	81.26	87.90	2029	118.75
19	60.68	65.42	70.68	76.48	82.56	89.17	2030	122.19
20	62.01	66.74	71.96	77.75	83.82	90.35	2031	125.77
							2032	129.45
							2033	133.06
							2034	138.33
							2035	143.82
							2036	146.84
							2037	151.45

Note: A "seasonal hydro project" is defined as a generation facility which produces at least 55% of its annual generation during the months of June, July, and August. Order 32802

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
May 6, 2013
$/MWh
New Contract

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	30.53	30.35	30.25	33.34	34.38	35.49	2012	30.53
2	30.45	30.30	31.73	33.84	34.91	36.12	2013	30.35
3	30.39	31.24	32.54	34.34	35.49	36.84	2014	30.25
4	31.04	31.93	33.19	34.89	36.15	42.24	2015	33.34
5	31.60	32.53	33.80	35.49	40.40	46.07	2016	34.38
6	32.12	33.10	34.43	38.97	43.70	49.15	2017	35.49
7	32.64	33.70	37.40	41.84	46.49	51.68	2018	36.81
8	33.18	36.24	39.94	44.34	48.85	53.77	2019	38.48
9	35.38	38.49	42.21	46.51	50.85	55.54	2020	61.36
10	37.37	40.54	44.22	48.38	52.56	57.11	2021	64.99
11	39.22	42.39	45.98	50.01	54.09	58.58	2022	68.98
12	40.90	44.02	47.53	51.49	55.54	59.93	2023	72.12
13	42.40	45.47	48.94	52.87	56.86	61.16	2024	74.35
14	43.74	46.79	50.26	54.15	58.07	62.32	2025	76.30
15	44.98	48.05	51.49	55.32	59.21	63.41	2026	78.89
16	46.16	49.21	52.62	56.42	60.29	64.46	2027	82.34
17	47.25	50.29	53.68	57.46	61.31	65.46	2028	85.02
18	48.27	51.30	54.69	58.46	62.28	66.45	2029	87.35
19	49.23	52.26	55.64	59.40	63.25	67.43	2030	90.32
20	50.14	53.17	56.55	60.32	64.20	68.34	2031	93.45
							2032	96.65
							2033	99.78
							2034	104.56
							2035	109.55
							2036	112.07
							2037	116.17

Note: "Other projects" refers to projects other than wind, solar, non-seasonal hydro, and seasonal 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/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
May 6, 2013
$/MWh
New Contract

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	30.53	30.35	34.36	60.45	61.88	63.39	2012	30.53
2	30.44	32.28	46.89	61.14	62.60	64.22	2013	30.35
3	31.65	40.94	51.50	61.83	63.38	65.14	2014	34.36
4	38.02	45.58	54.13	62.56	64.22	65.92	2015	60.45
5	42.08	48.60	56.00	63.34	64.98	67.02	2016	61.88
6	44.97	50.84	57.52	64.07	65.98	68.30	2017	63.39
7	47.21	52.67	58.76	65.00	67.16	69.58	2018	65.11
8	49.08	54.16	60.03	66.07	68.33	70.75	2019	67.20
9	50.64	55.61	61.34	67.16	69.43	71.81	2020	68.66
10	52.13	57.04	62.60	68.18	70.43	72.84	2021	72.40
11	53.58	58.39	63.76	69.13	71.41	73.89	2022	76.50
12	54.94	59.63	64.82	70.05	72.40	74.90	2023	79.75
13	56.19	60.75	65.84	70.99	73.36	75.85	2024	82.09
14	57.33	61.82	66.84	71.90	74.27	76.79	2025	84.15
15	58.40	62.86	67.80	72.76	75.16	77.70	2026	86.86
16	59.44	63.84	68.70	73.61	76.03	78.60	2027	90.43
17	60.43	64.77	69.58	74.43	76.89	79.48	2028	93.23
18	61.35	65.66	70.43	75.24	77.72	80.37	2029	95.68
19	62.24	66.52	71.26	76.03	78.57	81.28	2030	98.77
20	63.09	67.36	72.06	76.84	79.42	82.13	2031	102.02
							2032	105.34
							2033	108.61
							2034	113.51
							2035	118.64
							2036	121.29
							2037	125.53

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 SEASONAL HYDRO PROJECTS
May 6, 2013

$/MWh

New Contract

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	30.53	30.35	35.98	78.68	80.38	82.16	2012	30.53
2	30.44	33.06	56.49	79.50	81.23	83.12	2013	30.35
3	32.15	47.09	63.84	80.32	82.13	84.17	2014	35.98
4	42.45	54.46	67.89	81.17	83.11	85.07	2015	78.68
5	48.89	59.16	70.65	82.08	83.98	86.30	2016	80.38
6	53.40	62.55	72.81	82.92	85.11	87.71	2017	82.16
7	56.83	65.22	74.53	83.96	86.40	89.10	2018	84.16
8	59.61	67.38	76.19	85.15	87.69	90.39	2019	86.53
9	61.88	69.36	77.82	86.35	88.90	91.57	2020	88.27
10	63.96	71.23	79.35	87.48	90.02	92.71	2021	92.29
11	65.91	72.95	80.75	88.53	91.10	93.87	2022	96.68
12	67.70	74.51	82.03	89.56	92.20	94.98	2023	100.23
13	69.32	75.92	83.23	90.60	93.26	96.04	2024	102.87
14	70.78	77.24	84.41	91.61	94.27	97.08	2025	105.23
15	72.14	78.51	85.53	92.56	95.25	98.09	2026	108.25
16	73.44	79.70	86.59	93.50	96.22	99.08	2027	112.13
17	74.66	80.82	87.60	94.42	97.17	100.05	2028	115.25
18	75.80	81.89	88.58	95.32	98.09	101.04	2029	118.02
19	76.88	82.91	89.53	96.20	99.02	102.03	2030	121.44
20	77.91	83.89	90.45	97.08	99.96	102.97	2031	125.02
							2032	128.68
							2033	132.29
							2034	137.54
							2035	143.02
							2036	146.03
							2037	150.63

Note: A "seasonal hydro project" is defined as a generation facility which produces at least 55% of its annual generation during the months of June, July, and August. Order 32802

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
May 6, 2013
$/MWh
New Contract

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	30.53	30.35	32.38	53.39	54.72	56.12	2012	30.53
2	30.44	31.33	42.47	54.03	55.39	56.90	2013	30.35
3	31.04	38.11	46.23	54.67	56.11	57.77	2014	32.38
4	35.99	41.78	48.42	55.35	56.91	58.50	2015	53.39
5	39.17	44.22	50.00	56.09	57.62	59.55	2016	54.72
6	41.47	46.05	51.32	56.77	58.58	60.79	2017	56.12
7	43.28	47.58	52.41	57.65	59.70	62.02	2018	57.74
8	44.82	48.84	53.56	58.68	60.84	63.14	2019	59.72
9	46.11	50.10	54.76	59.73	61.89	64.16	2020	61.07
10	47.38	51.37	55.93	60.71	62.85	65.15	2021	64.70
11	48.65	52.59	57.01	61.62	63.79	66.15	2022	68.68
12	49.86	53.71	58.00	62.50	64.74	67.12	2023	71.82
13	50.97	54.73	58.94	63.40	65.66	68.04	2024	74.05
14	51.99	55.70	59.88	64.27	66.53	68.93	2025	75.99
15	52.95	56.66	60.78	65.09	67.38	69.81	2026	78.58
16	53.90	57.57	61.64	65.90	68.22	70.67	2027	82.03
17	54.80	58.43	62.46	66.69	69.03	71.51	2028	84.70
18	55.64	59.26	63.27	67.47	69.83	72.37	2029	87.02
19	56.46	60.06	64.05	68.23	70.65	73.24	2030	89.99
20	57.24	60.83	64.81	69.00	71.47	74.06	2031	93.11
							2032	96.31
							2033	99.44
							2034	104.21
							2035	109.20
							2036	111.71
							2037	115.81

Note: "Other projects" refers to projects other than wind, solar, non-seasonal hydro, and seasonal 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 NON-SEASONAL HYDRO PROJECTS
May 6, 2013

$/MWh

New Contract

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	30.53	30.35	56.39	59.86	61.28	62.78	2012	30.53
2	30.44	42.87	58.06	60.54	62.00	63.61	2013	30.35
3	38.44	48.11	59.05	61.23	62.77	64.52	2014	56.39
4	43.19	51.03	59.88	61.96	63.62	65.30	2015	59.86
5	46.28	53.03	60.67	62.75	64.37	66.40	2016	61.28
6	48.53	54.60	61.47	63.47	65.38	67.69	2017	62.78
7	50.32	55.94	62.21	64.40	66.55	68.97	2018	64.50
8	51.85	57.08	63.11	65.48	67.73	70.14	2019	66.58
9	53.15	58.26	64.13	66.57	68.83	71.21	2020	68.03
10	54.43	59.47	65.16	67.59	69.84	72.25	2021	71.76
11	55.72	60.65	66.14	68.55	70.82	73.30	2022	75.85
12	56.95	61.75	67.06	69.48	71.82	74.31	2023	79.09
13	58.09	62.76	67.95	70.42	72.79	75.27	2024	81.42
14	59.14	63.73	68.85	71.34	73.70	76.22	2025	83.48
15	60.14	64.69	69.72	72.21	74.60	77.14	2026	86.18
16	61.12	65.61	70.55	73.06	75.48	78.05	2027	89.74
17	62.05	66.48	71.37	73.90	76.35	78.93	2028	92.52
18	62.93	67.32	72.17	74.72	77.19	79.84	2029	94.96
19	63.78	68.14	72.95	75.52	78.05	80.76	2030	98.05
20	64.60	68.94	73.72	76.34	78.92	81.63	2031	101.28
							2032	104.60
							2033	107.85
							2034	112.75
							2035	117.86
							2036	120.50
							2037	124.73

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 SEASONAL HYDRO PROJECTS
May 6, 2013

$/MWh

New Contract

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	30.53	30.35	73.97	77.70	79.38	81.15	2012	30.53
2	30.44	51.32	75.76	78.51	80.23	82.10	2013	30.35
3	43.85	59.45	76.88	79.32	81.12	83.14	2014	73.97
4	51.37	63.87	77.82	80.17	82.09	84.05	2015	77.70
5	56.14	66.82	78.73	81.07	82.97	85.27	2016	79.38
6	59.55	69.04	79.65	81.91	84.09	86.68	2017	81.15
7	62.20	70.89	80.50	82.95	85.38	88.07	2018	83.13
8	64.39	72.42	81.51	84.14	86.67	89.36	2019	85.49
9	66.22	73.93	82.64	85.35	87.88	90.54	2020	87.21
10	67.95	75.43	83.78	86.48	89.00	91.69	2021	91.22
11	69.61	76.85	84.86	87.54	90.09	92.85	2022	95.60
12	71.17	78.17	85.87	88.57	91.19	93.97	2023	99.13
13	72.59	79.37	86.86	89.61	92.26	95.03	2024	101.75
14	73.89	80.52	87.86	90.63	93.28	96.07	2025	104.10
15	75.12	81.64	88.83	91.59	94.27	97.10	2026	107.10
16	76.30	82.72	89.75	92.54	95.24	98.10	2027	110.97
17	77.42	83.73	90.66	93.47	96.20	99.08	2028	114.07
18	78.48	84.70	91.54	94.37	97.13	100.07	2029	116.82
19	79.49	85.65	92.41	95.26	98.08	101.08	2030	120.23
20	80.46	86.56	93.26	96.16	99.03	102.03	2031	123.79
							2032	127.44
							2033	131.02
							2034	136.26
							2035	141.72
							2036	144.71
							2037	149.29

Note: A "seasonal hydro project" is defined as a generation facility which produces at least 55% of its annual generation during the months of June, July, and August. Order 32802

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
May 6, 2013
$/MWh
New Contract

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	30.53	30.35	49.58	52.95	54.27	55.67	2012	30.53
2	30.44	39.60	51.20	53.59	54.95	56.45	2013	30.35
3	36.34	43.71	52.15	54.23	55.67	57.32	2014	49.58
4	40.03	46.06	52.93	54.91	56.47	58.05	2015	52.95
5	42.46	47.70	53.67	55.65	57.17	59.10	2016	54.27
6	44.26	49.00	54.43	56.33	58.13	60.34	2017	55.67
7	45.72	50.15	55.13	57.21	59.26	61.57	2018	57.29
8	46.99	51.14	55.98	58.25	60.40	62.70	2019	59.26
9	48.08	52.19	56.96	59.30	61.45	63.73	2020	60.60
10	49.20	53.29	57.96	60.28	62.42	64.72	2021	64.22
11	50.34	54.38	58.89	61.20	63.36	65.73	2022	68.20
12	51.45	55.39	59.77	62.09	64.32	66.70	2023	71.34
13	52.48	56.33	60.62	62.99	65.25	67.62	2024	73.55
14	53.43	57.23	61.49	63.87	66.12	68.53	2025	75.49
15	54.34	58.12	62.32	64.70	66.99	69.41	2026	78.07
16	55.24	58.98	63.12	65.52	67.83	70.28	2027	81.51
17	56.10	59.80	63.90	66.32	68.66	71.13	2028	84.18
18	56.91	60.59	64.67	67.11	69.47	72.00	2029	86.50
19	57.70	61.37	65.42	67.88	70.29	72.89	2030	89.46
20	58.46	62.12	66.15	68.66	71.13	73.72	2031	92.57
							2032	95.76
							2033	98.88
							2034	103.64
							2035	108.62
							2036	111.13
							2037	115.22

Note: "Other projects" refers to projects other than wind, solar, non-seasonal hydro, and seasonal 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/.