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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

Arizona Corporation Commission
DOCKETED
AUG 05 2016
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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF REVISED APS PARTIAL REQUIREMENTS RATE SCHEDULE EPR-2

DOCKET NO. E-01345A-16-0272

APPLICATION

Arizona Public Service Company ("APS" or "Company") hereby submits this application requesting approval of revisions to the Company's partial requirements rate schedule EPR-2. EPR-2 provides an option for customers with qualifying facilities (QFs)—renewable and combined heat and power generators that meet the requirements under 18 CFR, Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission regulations—under 100 kW to sell their excess generation to APS. Specifically, the Company is requesting (i) a routine revision to the purchase rate for excess generation from participating QF customers, which is based on avoided generation costs as mandated by federal and state regulations; and (ii) a limitation of contracts for QFs greater than 100 kW to terms not exceeding two years. Just as importantly, what APS is *not* requesting in this Application is any change in rate design or to the terms and conditions of net metering, which is itself subject to an entirely different rate schedule, EPR-6. Those issues, although of vital importance, are subjects in APS's pending general rate case and will be decided by the Commission in due course in that wholly separate proceeding.

APS's request to update its avoided cost is a routine procedure that occurs from time to time. In Decision No. 52345 (July 27, 1981), the Commission concluded that avoided cost was subject to change because of variations in fuel and purchased power costs:

> Rate and *other contract provisions* covering sales to and purchases from QF's, including rates for supplementary, back-up, interruptible and maintenance power, shall be subject to changes from time to time as filed with and prescribed by the Arizona Corporation Commission. Adjustments to the purchase rates may be permitted as often as quarterly to reflect variations in fuel and purchased power costs.

See Cogeneration and Small Power Production Policy attached to Decision No. 52345 at 9 (emphasis supplied). APS makes this request to better align its avoided cost with current costs. The proposed purchase rates reflect the Company's forecasted avoided generation costs for the calendar year January 2016 through December 2016.

Similarly, APS's request to establish the term for avoided cost QF contracts arises out of the need to manage ever-changing market conditions. As the Commission is well aware, avoided generation costs have been steadily dropping for some years now and are not forecasted to increase anytime soon. In fact, negative avoided costs are already experienced during some times of day and seasons of the year on a regular basis. Despite this consistently changing market environment, QFs can seek contracts under PURPA "over a specified period of time." *See* 18 CFR § 292.304(d). Although PURPA leaves to the states what that specified period of time should be, PURPA does permit QFs to obtain an avoided cost that is either the "as available" actual avoided cost updated from time-to-time over the term of the contract or an avoided cost that is established at the beginning of the contract, and does not change over the life of the contract.[1] Moreover,

[1] To date, APS's limited experience with QF contracts has been at the "as available" avoided cost pricing.

PURPA require APS to purchase energy and capacity from QFs, regardless of whether such energy or capacity is needed or can be acquired more cheaply from the competitive wholesale market. Under these circumstances, the longer APS is required to pay a locked-in avoided cost determined by the Commission, the more likely it becomes that APS customers will overpay for something for they don't need in the first place. It is one thing to pay an avoided cost forecasted over 2 years. It is an entirely different thing to pay that avoided cost forecasted over 20 years. This dynamic was recognized by the Idaho Public Utilities Commission in a recent decision limiting any QF contract for suppliers over 100 kW to two years, absent special circumstances. There, the Idaho Commission stated: "there is no obligation under PURPA for a utility to enter into contracts to make purchases which would result in rates which are not 'just and reasonable to electric consumers of the electric utility and in the public interest' or which exceed 'the incremental cost to the electric utility of alternative energy." *In the Matter of Idaho Power Company, et al.*, 2015 WL 6958997 (Idaho P.U.C. 2015) at 9.[2] A copy of that decision is attached as Exhibit A. For the same reasons stated above and so well-articulated in the Idaho decision referenced above, APS asks for language in rate schedule EPR-2 adopting a similar two year limitation for these larger QF suppliers.

The revised Schedule EPR-2 is provided as Exhibit B, with a redlined copy provided as Exhibit C for the Commission's convenience. The Company is seeking specific Commission approval of this partial requirement rate schedule, including both the new avoided cost rate and the two year limit on larger QF contracts. Therefore, APS

[2] The Idaho Commission relied heavily on an Idaho Supreme Court ruling in *Idaho Power Co. v. Idaho Public Utilities Commission*, 316 P. 3d 1278 (2013) wherein the Court stated: "[the state commission] has discretion in determining the manner in which the [PURPA] rules will be implemented" and also it "is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements ...." *Id.* At P. 3d 1280 and 1284. Federal authorities cited by the Court for its position on the state's power to determine issues regarding QF contracts included the seminal case of *FERC v. Mississippi*, 456 U.S. 742, 751 (1982); and also *Power Resources Group v. PUC of Texas*, 422 F.3d 231 (5th Cir. 2005).

waives any requirement that the Commission take action within a thirty-day period, as referenced in A.R.S. § 40-367.

RESPECTFULLY SUBMITTED this 5th day of August 2016.

By: Thomas L. Mumaw
Thomas L. Mumaw

Attorney for Arizona Public Service Company

ORIGINAL and thirteen (13) copies
of the foregoing filed this 5th day of
August 2016, with:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

2015 WL 6958997 (Idaho P.U.C.)
Slip Copy

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS

IPCE1501

IN THE MATTER OF AVISTA CORPORATION'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS

AVUE1501

IN THE MATTER OF ROCKY MOUNTAIN POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS

PACE1503
33419

Idaho Public Utilities Commission

November 5, 2015

BY THE COMMISSION.

*1 On September 10, 2015, Clearwater Paper Corporation and J.R. Simplot Company (the "Petitioners") filed a Petition for Reconsideration in the above-referenced consolidated cases. The Petitioners requested reconsideration of the Commission's final **Order** No. **33357** that reduced the length of certain PURPA contracts from 20 years to two years. The Petitioners generally raised three arguments. First, they argued that the Commission's two-year contract is contrary to the PURPA regulation "because it deprives the IRP-based QFs of a long-term, fixed contract price to sell energy *and* capacity with prices calculated at the outset of the obligation." Petition at 11 (underline added). Second, they argued that the new two-year contract term fails to provide each qualifying facility (QF) with a fixed-price for "energy and capacity calculated at the time the QF obligates itself to sell its output to an Idaho utility...." *Id.* at 2. Finally, they asserted the Commission's "capacity adjustment" (used to determine the date when the QF would be eligible for capacity payments) "is made up of whole cloth." *Id.* at 16. They alleged that no party discussed the capacity adjustment in its testimony. The Petitioners concluded that the Commission's creation of the capacity adjustment "is not supported by any evidence on the record whatsoever." *Id.* at 17.

Clearwater and Simplot requested that the Commission either retain the prior 20-year contract term or adopt their alternative proposal for a "20-year contract with an update to energy prices in new PURPA contracts in contract year 10...." Petition at 15. The Petitioners maintained that either alternative would meet the minimum requirements of FERC's regulations. *Id.* They offered to submit further briefing, oral argument, or any further technical testimony the Commission may request. *Id.* at 17.

On September 17, 2015, Avista Corporation, Idaho Power Company, and Rocky Mountain Power (collectively the "Utilities") filed a timely joint answer urging the Commission to deny reconsideration. The Utilities maintained that the Commission's final **Order** No. **33357** properly found that 20-year PURPA contracts are inconsistent with the public interest. They argued the Commission's decision to set the maximum standard contract term to two years more accurately reflects true avoided costs and appropriately balances "the competing interest of protecting utility customers and developing QF generation." Answer at 11. They insisted that the PURPA regulations issued by the Federal Energy Regulatory Commission (FERC) are silent as to the length of a contract and the Commission acted within its discretion in reducing the contract term. *Id.* at 6. The Utilities also asserted that the Commission's final **Order** is based upon substantial and competent evidence in the record. *Id.* at 11.

*2 On October 8, 2015, the Commission issued **Order** No. 33395 granting reconsideration on the issues raised by Clearwater and Simplot. The Commission noted that it had compiled an extensive evidentiary record in this case and determined that further argument and briefing was not necessary. **Order** No. 33395 at 2. After having thoroughly reviewed the issues raised in the Petition for Reconsideration and the record in this case, the Commission dismisses the issues raised in the Petition for

Reconsideration as discussed in greater detail below.

BACKGROUND

A. PURPA

Congress enacted the Public Utility Regulatory Policies Act (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). Under the Act, FERC prescribes rules for PURPA's implementation. 16 U.S.C. § 824a-3(a), (b). State regulatory authorities such as the Idaho Public Utilities Commission implement FERC regulations, but have "discretion in determining the manner in which the rules will be implemented." *Idaho Power Co. v. Idaho PUC,* 155 Idaho 780, 782, 316 P.3d 1278, 1280 (2013), *citing FERC v. Mississippi,* 456 U.S. at 751. The Idaho Supreme Court has observed that the Commission has the authority to implement PURPA and that this grant of authority is broad. *Idaho Power,* 155 Idaho at 787, 316 P.3d at 1285; *Rosebud Enterprises* v. *Idaho PUC (Rosebud I),* 128 Idaho 624, 627, 917 P.2d 781, 784 (1996); *A.W. Brown v. Idaho Power Co.,* 121 Idaho 812, 814, 828 P.2d 841, 843 (1992).

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." **Order** No. 32697 at 7; 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a) (exceptions to the "must purchase" provision inapplicable in this case). Electric utilities are required to purchase power from QFs at rates equivalent to a utility's "avoided cost" and approved by this Commission. 16 U.S.C. § 824a-3; *Idaho Power,* 155 Idaho at 789, 316 P.3d at 1287. The purchase or 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 I,* 128 Idaho at 627, 917 P.2d at 784; 18 C.F.R. § 292.101(b)(6). The avoided cost rate must be "just and reasonable to the electric consumers ... and in the public interest" and "shall not discriminate against [QFs]." 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304. In addition, utilities shall not be required to pay more than their avoided costs when purchasing power from a QF. *Rosebud Enterprises v. Idaho PUC (Rosebud II),* 128 Idaho 609, 614, 917 P.2d 766, 771 (1996), *citing* 16 U.S.C. § 824a-3(b) (PURPA regulations shall not "provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."), *Rosebud I,* 128 Idaho at 627, 917 P.2d at 784.

*3 This Commission has established two methods of calculating avoided cost, depending on the size of the QF project: (1) the surrogate avoided resource (SAR) methodology, and (2) the integrated resource plan (IRP) methodology. *See* **Order** No. 32697 at 7-8. The Commission uses the SAR methodology to establish what is commonly referred to as "published" or standard avoided cost rates. *Id;* 18 C.F.R. § 292.304(c). Published rates are available for wind and solar QFs with a design capacity not to exceed 100 kilowatts (kW), and for QFs of all other resource types with a design capacity of up to 10 average megawatts (aMW).[1] **Order** No. 32697 at 7-8. For QFs with design capacity above the published rate eligibility caps, avoided cost rates are "individually negotiated by the QF and the utility" using the IRP methodology based on the specific characteristics of the resource. **Order** Nos. 32697 at 2; 32176 at 1. Since 2002, the standard length for both SAR-based contracts and IRP-based contracts was set by the Commission at 20 years. **Order** Nos. 32697 at 24-25, **33357** at 11. In that **Order** the Commission also found that shorter or longer contracts would be permissible on a case-by-case basis. *Id.* at 25.

At the option of each QF, the utility's avoided cost power rate shall be calculated either at the time of delivery or at the time the sales obligation is incurred. *Rosebud II,* 128 Idaho at 621, 971 P.2d at 778; 18 C.F.R. § 292.304(d). Avoided costs are generally divided into two components: capacity rates and energy rates. *See* **Order** No. 32697 at 15. Capacity rates reflect the ability of the utility to generate electric power at any instant in time and are measured in megawatts (MW). A QF that provides capacity to the utility allows the utility in theory to avoid building new generation or purchasing firm power from another supplier. Energy rates reflect the costs of supplying electricity over time and are measured in megawatt hours (MWh). For example, one MW of capacity supplied for one hour equals one MWh of energy.

B. THE UTILITIES' REQUESTS TO REDUCE THE LENGTH OF PURPA CONTRACTS

On January 30, 2015, Idaho Power Company filed a Petition asking the Commission to reduce the length of its IRP-based PURPA contracts from 20 years to two years. Avista and Rocky Mountain subsequently filed similar petitions and the three cases were consolidated into a single proceeding. **Order** No. 33250. While the Commission investigated the issue of contract length, it granted temporary relief to the three utilities by reducing the length of new PURPA contracts to five years. *Id.* at 8; *see* **Order** No. **33357** at 6-7 (summarizing petitions to clarify the scope of the case).

***4** 1. Idaho Power. The Company asserted that 20-year fixed-rate contracts are no longer reasonable. Idaho Power insisted it has reached a point where the cumulative capacity of the proposed PURPA projects will exceed the Company's operational need by a large margin. Idaho Power's Senior Vice President of Power Supply testified that the Company does not need the additional generation. She reported that the Company's peak load for its system in 2014 was about 3,184 MW while its minimum load was approximately 1,073 MW. **Order** No. **33357** at 13; Tr. at 107-108. Idaho Power asserted it had more than 1,161 megawatts (MW) of PURPA projects under contract and an additional 1,326 MW of new solar projects in the queue. **Order** No. **33357** at 3-4; Exh. 11 at 4. The Company maintained that the recent influx of PURPA generation places undue financial and operational risks on customers at a time when the utility has sufficient resources to meet customer demand through 2024. **Order** No. **33357** at 4; Tr. at 281.

The Company also asserted in its initial Petition that "the continued creation of 20year term [PURPA] contracts places undue risk on customers" and is contrary to the public interest. Idaho Power Petition at 2, 27-34. Idaho Power complained that if all the proposed solar projects come on-line, it would represent a "long-term financial obligation to customers over 20 years of approximately $2.1 billion, in addition to the existing $2.6 billion obligation over the life of the Company's [PURPA] projects already on-line and operational." *Id.* at 3.

2. Rocky Mountain Power. Rocky Mountain requested a permanent reduction in its IRP-based PURPA contracts from 20 years to three years. The Company asserted in its Petition that five days after the Commission granted Idaho Power interim relief, Rocky Mountain received four requests from solar developers in Idaho Power's service territory seeking to sell or "wheel" 130 MW of solar power to Rocky Mountain. Rocky Mountain Petition at 4-5, 16. Rocky Mountain insisted these four projects sought to wheel power to it to obtain a more favorable 20-year contract when Idaho Power contracts were temporarily reduced to five years. *Id.*, n.5.

Like Idaho Power, Rocky Mountain asserted it had no need for additional generating resources until 2028. *Id.* at 3, n.4, Tr. at 429. Adding the proposed PURPA projects to the Company's existing PURPA contracts would total approximately 465 MW. Petition at 5. At full nameplate capacity, this would be enough to supply 108% of Rocky Mountain's average retail load in 2014 and 275% of its minimum Idaho retail load in 2014. Tr. at 427. The Company also insisted that the reduction was necessary to be "consistent with the Company's hedging and trading policies," the length of its non-PURPA energy contracts, and to more closely align with the two-year Integrated Resource Plan (IRP) cycle. Petition at 3-4.

***5** 3. Avista. If the Commission granted permanent relief to Idaho Power and Rocky Mountain by shortening their IRP contracts, Avista requested that it be granted the same relief. **Order** No. **33357** at 18, *citing* Tr. at 404, 408. Avista's witness acknowledged that Avista had not received any proposals for solar projects, but testified that having contract lengths in excess of the other two utilities could cause QF developers to seek contracts with Avista simply to obtain longer term contracts. *Id.*, Tr. at 406-07. Avista also recommended that the Commission allow IRP contracts longer than five years if such contracts are in the best interest of ratepayers. *Id.*, Tr. at 410.

FINAL ORDER NO. 33357

A. 20-YEAR CONTRACTS ARE UNREASONABLE

In its final **Order** No. **33357**, the Commission found based upon substantial and competent evidence that 20-year IRP contracts are unreasonable and inconsistent with the public interest. **Order** No. **33357** at 23. The Commission cited several reasons in support of its decision to shorten IRP-based contracts. First, the Commission found that neither PURPA nor its implementing regulations "specify a mandatory length for PURPA contracts." *Id.* at 12. The Commission noted that no party contested that "FERC regulations do not dictate a specific number of years or establish a time period for PURPA contracts." *Id.*, *citing* Tr. at 589, *see also* 215-16, 410-11, 513-15.

Second, the Commission found that 20-year contracts are unreasonable because the length exacerbates overestimations to a point that avoided cost rates are inconsistent with the public interest. The Commission found there was general agreement among the parties that the avoided cost rates for IRP projects are declining and will continue to decline in the future. **Order** No. **33357** at 22, *citing* Tr. at 260-61, 372, 630-31, 642. With long-term avoided cost rates in decline, allowing QFs to fix their avoided cost rates for 20 years when they enter into their contract/obligation, will result in avoided cost rates which exceed or "overestimate" avoided cost rates in the future. *Id.* at 23. This "'overestimation' will become more significant over the duration of the [20-year] contract." *Id.* The Commission observed that when FERC issued its initial PURPA regulations in 1980, FERC recognized that avoided costs calculated at the time parties enter into a power contract may exceed the actual avoided costs at the time the power is delivered in the future. 45 Fed.Reg. 12,214 at 12,224 (Feb. 25, 1980). As FERC explained in its **Order** No. 69, overestimations will "subsidize the [QF] at the expense of the utility's other ratepayers." **Order** No. **33357** at 22-23, *citing* 45 Fed.Reg. at 12,224; Tr. at 575-77. FERC discounted the concern about long-term avoided costs exceeding actual avoided costs at the time of delivery (i.e., overestimations) because it theorized that over time "'overestimations' and "underestimations' of avoided costs will balance out." *Id.* However, the Commission found that based upon the record in this proceeding 20-year IRP contracts with fixed avoided cost rates will exceed actual avoided costs and are inconsistent with the public interest. 16 U.S.C. § 824a-3(b).

*6 Third, the Commission found that both Idaho Power and Rocky Mountain presented persuasive evidence that they did not need additional generation and each currently has a capacity surplus. **Order** No. **33357** at 24. The Commission specifically found that the two utilities' supply of PURPA and non-PURPA power exceeds their average Idaho loads. *Id., citing* Tr. at 111, 117, 931. "The abundance of PURPA generation extends the utilities' capacity surpluses to 2024 for Idaho Power and 2028 for [Rocky Mountain]." *Id.* at 24.

The Commission also rejected two similar but different proposed alternatives in lieu of shortening the term of the contracts. More specifically, the Petitioners urged the Commission to continue the 20-year contract but "adjust the energy component in each of the last 10 years of the standard contract." **Order** No. **33357** at 23 (emphasis added), *citing* Tr. at 842. The other alternative proposed by the Sierra Club was to retain the 20-year term but reset the energy rate just once in the eleventh year of the contract, i.e., in year 11. Tr. at 701-03. The Commission rejected both of these alternatives based upon concern that an adjustable rate 20-year contract runs the risk of undermining FERC regulations that mandate a "fixed-rate" at the time the contract or obligation is entered. *Id., citing* 18 C.F.R. § 292.304(d)(2)(ii); Tr. at 213-15. The Commission also found that the ability to ensure that avoided cost rates remain accurate can best be accomplished through successive short-term contracts. **Order** No. **33357** at 24.

B. THE TWO-YEAR CONTRACT

Because neither PURPA nor FERC's implementing regulations expressly specify a length for PURPA contracts, the Commission found that setting an appropriate contract length is left to its discretion. The Commission noted that the Idaho Supreme Court has stated that the Commission has the authority to implement PURPA and that this grant of authority is broad. **Order** No. **33357** at 3, *citing Idaho Power,* 155 Idaho at 787, 315 P.3d at 1285; *Rosebud I,* 128 Idaho at 627, 917 P.2d at 784; *A. W. Brown,* 121 Idaho at 814, 828 P.2d at 843. The Commission also noted that it "is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements...." **Order** No. **33357** at 12, *quoting Idaho Power,* 155 Idaho at 786, 316 P.3d at 1284, *quoting Power Resources Group v. PUC of Texas, All* F.3d 231, 238 (5th Cir. 2005).

*7 Having found that the standard 20-year IRP-based contract was unreasonable and no longer in the public interest, the Commission determined that the length of new IRP-based contracts should be set at two years for all three utilities. **Order** No. **33357** at 25; 16 U.S.C. § 824a-3(b)(l). The Commission cited several reasons to support its finding. First, the Commission found that shorter contracts have the potential to benefit both the QF and the utility's customers. "By adjusting avoided cost rates more frequently, avoided costs become a truer reflection of the actual costs avoided by the utility and allow QFs and ratepayers to benefit from normal fluctuations in the market." *Id.* at 23. In other words, when avoided costs increase or decrease, both the QF and ratepayers have the opportunity to benefit.

Second, the Commission found that reducing the contract length to two years does not

EXHIBIT A

> prevent a QF from selling energy to a utility over the course of 20 years - or longer. PURPA's "must purchase" provision requires the utility to continue to purchase the QF's power. [16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a).] As long as projects continue to offer power to utilities, utilities must continue to purchase such power under PURPA. A shorter contract length merely functions as a reset for calculation of the avoided costs in **order** to maintain a more accurate reflection of the actual costs avoided by the utility over the long term.

Order No. **33357** at 23. In addition, most QFs choose to have their avoided cost rates fixed at the time the contract/obligation is incurred for the duration of the contract. *Id.* at 22.

Third, the Commission determined it was reasonable and logical to set the length of IRP contracts at two years to coincide with the two-year planning cycle for the integrated resource planning process. "Matching IRP contracts to the IRP planning cycle provides more accurate IRP avoided costs, reduces price risks, and provides more forecast certainty." *Id., citing* Tr. at 486, 127-28, 287, 902-05, 915-17. The Commission also found that the two-year contract better matches the utilities' hedging and risk management practices.

C. THE CAPACITY ADJUSTMENT AND EXCEPTIONS TO TWO-YEAR CONTRACTS

In reducing the length of IRP-based contracts to two years, the Commission recognized that two adjustments or exceptions were necessary. The first is referred to as the "capacity adjustment," and the second is the "exception" to limiting contracts to two years.

***8** 1. Capacity Adjustment. The capacity adjustment addressed concerns raised by parties opposed to reducing the 20-year contracts because "short-term contracts will not contribute to the avoidance of utility capacity/generation." **Order No. 33357** at 26. The capacity adjustment was intended to ensure that the QF will be compensated for providing capacity[3] to the utility when "the utility becomes capacity deficient." **Order No. 33357** at 25, *quoting* **Order** No. 32697 at 21. Because each utility's capacity deficiency date is updated and reset every two years as part of the IRP methodology, the Commission was concerned that new two-year IRP-based contracts "would be unlikely to reach a capacity deficiency date." **Order** No. **33357** at 25. In other words, under the two-year term, a contracting QF might never reach a point where its capacity is contributing to the utility's system and would, therefore, never receive capacity payments.

To remedy this concern, the Commission found it

> reasonable for utilities to establish capacity deficiency at the time the initial IRP-based contract is signed. As long as the QF renews its contract and continuously sells power to the utility, the QF is entitled to capacity [rates] based on the capacity deficiency date established at the time of its initial contract. For example, if the QF comes on-line in 2017 and the utility [becomes] capacity deficient in 2020, the QF would be eligible for capacity payments in the second year of its second contract [(i.e., 2020)] and thereafter if in continuous operation. This adjustment recognizes that in ensuing contract periods, the QF is considered part of the utility's resource stack and will be contributing to reducing the utility's need for capacity.

Order. No. **33357** at 25-26.

2. Exceptions to Limiting Contracts to Two Years. Avista's witness recommended that the Commission allow IRP contracts to exceed the standard contract term of two, three or five years "in the event a very favorable PURPA opportunity arises." Tr. at 404, 410; *see also* Tr. at 908-10. The Commission adopted this recommendation and found there may be circumstances that justify IRP-based contracts that are longer than two years. **Order** No. **33357** at 26. In instances when the utility and the project developer believe that a contract term longer than two years is justified, "utilities are directed as part of their standard negotiation process to fairly evaluate such a request." *Id.* The Commission also noted that approving IRP-based contracts in excess of the standard length (i.e., two years) "is consistent with our prior **Orders.**" **Order** Nos. 27213; 26576 at 6-7; 32697

at 25.

SCOPE OF RECONSIDERATION

A. LEGAL STANDARDS

*9 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. *Idaho Code* § 61-626; Rule 332, IDAPA 31.01.01.332. If the Commission believes its final **order** "should be changed, the Commission may … change the same." *Idaho Code* § 61626(3). An **order** on reconsideration that changes the original final **order**, shall have the same force and effect as the original **order**. *Id.; see also Idaho Code* § 61-624.

B. UNDERLYING FACTS

The scope of final **Order** No. **33357** was limited to issues of reducing the length of IRP-based PURPA contracts. **Order** No. 33253 at 4. The parties proposed and the Commission approved that the standard length for SAR-based contracts remain unchanged at 20 years. *Id.,* **Order** No. **33357** at 7. Clearwater and Simplot are the only parties or persons to seek reconsideration of the Commission's final **Order**. *Idaho Code* § 61-626.

Both Petitioners operate existing cogeneration facilities and both expressed an interest in developing new cogeneration facilities at their industrial plants. Tr. at 769, 771. A cogeneration facility typically relies on a host's industrial process to produce electricity in conjunction with the activities of the host facility. 18 C.F.R. § 292.202(c). Cogeneration projects with power output of 10 average MW (aMW) or less are eligible to receive published SAR-based, avoided cost energy and capacity rates with 20-year contracts. **Order** No. **33357** at 3.

Clearwater Paper operates four cogeneration facilities at its manufacturing facility near Lewiston that are capable of generating a total of approximately 111 MW. Petition at 3; Tr. at 769. Simplot currently operates a 15.9 MW cogeneration facility that uses waste heat to generate electricity. Petition at 3; Tr. at 767. Although Simplot's QF has the capability to generate in excess of 10 aMW, it "has thus far chosen to enter into standard rate contracts for QFs generating up to 10 aMW of generation." Petition at 3. In other words, Simplot has not sought IRP-based avoided cost rates but has elected to be paid the published SAR-based avoided cost rates for small cogeneration QFs (less than 10 aMW).

*10 At the technical hearing, the Petitioners' witness Dr. Reading was asked about the lengths of the Petitioners' PURPA contracts.[3] He deferred to the Commission's records for the history of contract length. Tr. at 858. Since enactment of PURPA in 1978, neither Clearwater nor Simplot has sought a 20-year contract for their existing facilities.[4] The longest PURPA contract for Simplot's existing facility was seven years (2006 -2013). **Order** No. 30028. Simplot also has had several one and two-year contracts. **Order** Nos. 28739, 29577, 32790, 33240. In Clearwater's case, its two longest PURPA contracts were each ten years. **Order** Nos. 23858, 29418. In 2013, Clearwater agreed to sell its available power output to Avista under a non-PURPA sales contract that extends to 2018. Tr. at 858-59, 931-32, *citing* **Order** No. 32841. Earlier this year, Clearwater and Avista requested and the Commission approved extending their non-PURPA contract for an additional three years, until June 2021. **Order** No. 33350; Tr. at 932, n.1.

ISSUES IN DISPUTE

A. PURPA DOES NOT AUTHORIZE THE QF TO SPECIFY THE LENGTH OF THE CONTRACT

The Petitioners raise a number of inter-related arguments generally urging the Commission to reconsider its decision to shorten IRP-based contracts to two years. They first insist that FERC's PURPA regulation at 18 C.F.R. § 292.304(d)(2)(ii) permits a QF to determine the length of IRP-based contracts. They argue that this section requires that each QF "shall" be provided with the following options:

(1) to elect to sell energy and capacity [to the utility];

(2) to elect to sell such energy and capacity over a term specified by the QF; and

*11 (3) to elect that the obligation contain rates for energy and capacity calculated at the time the QF incurs that obligation.

Petition at 9 (emphasis added). They maintain that use of the word "shall" makes it mandatory that QFs have the authority to dictate the length of IRP contracts.

In their answer, the Utilities assert the Petitioners misrepresent the plain language of section 292.304(d)(2) and "authorities related to a legally enforceable obligation in an unsuccessful effort to create a requirement for **long-term** contractual commitments." Joint Answer at 3 (emphasis original). They specifically attack the Petitioners' claim that section 292.304(d)(2) allows a QF to specify the term of the contract. They allege that a review of the section's explicit language reveals that QFs do not have the authority to specify the length of IRP-based contracts with utilities. Answer at 3, 4-6.

The Utilities included Section 292.304(d) in their answer. This section states in full:

Each qualifying facility shall have the option either:

1. To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

2. To provide energy or capacity over a specified term, in which case the rates for such purchase shall, at the option of the qualifying facility exercise prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

18 C.F.R. § 292.304(d) (emphasis added). They maintained the phrase "over a specified term" means there is "a term" or contract length - not that the QF is entitled to specify the length of the contract. Answer at 5.

The Utilities also observed that the Commission's **Order** recites that there was no dispute among the parties regarding the fact that FERC regulations "do not dictate a specific number of years or establish a time period for PURPA contracts." Answer at 4, *quoting* **Order** No. **33357** at 12. The Utilities asserted that the PURPA regulations are silent as to a specific contract length and there is nothing in the regulations that allow a QF to specify the length of a PURPA contract.

Commission Findings: We are not persuaded that the Petitioners' (as qualifying facilities) get to choose the length or term of IRP contracts for several reasons. First, PURPA requires State Commissions to implement PURPA. 16 U.S.C. § 824a-3(f)(1); **Order** 69, 45 Fed.Reg. at 12,216 ("The implementation of these [PURPA] rules is reserved to the State regulatory authorities....") This Commission has authority to implement PURPA and "has discretion in determining the manner in which the [PURPA] rules will be implemented." *Idaho Power*, 155 Idaho at 782, 316 P.3d at 1280, *citing FERC v. Mississippi*, 456 U.S. at 751. It "is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements...." *Idaho Power*, 155 Idaho at 786, 316 P.3d at 1284, *quoting Power Resources Group v. PUC of Texas*, 422 F.3d 231, 238 (5th Cir. 2005) (emphasis added).

*12 Since PURPA was first enacted, this Commission has set the lengths for PURPA contracts. Over the years, the Commission has set different contract terms of 35 years, 20 years, and as short as 5 years. **Order** No. **33357** at 11 (citations omitted). In setting contract lengths, the Commission has "considered many factors (price risks, forecasting uncertainty, financial needs, amortization, plant durability)." *Id.* at 12, *citing* **Order** No. 32125. We found in **Order** No. **33357** and affirm in this **Order** that the Commission has discretion to set the length of PURPA contracts. **Order** No. **33357** at 12. Indeed, the parties did not contest "that PURPA, and its implementing regulations are silent as to a specific contract length.... Even Mr. Wenner acknowledged that FERC regulations do not dictate a specific number of years or establish a time period for PURPA contracts. Tr. at 589." **Order** No. **33357** at 12 (other citations omitted). Moreover, Clearwater and Simplot have failed to identify any other State where the QF has the unilateral authority to specify the term of a PURPA contract.

We reject the Petitioners' assertion that they may unilaterally choose the length of their IRP contracts. As our Idaho Supreme Court has noted on many occasions, "[s]tatutory interpretation begins with the plain meaning of the statute. If the statutory language is clear and unambiguous, this Court need merely apply the statute without engaging in statutory interpretation." *Herman v. Herman,* 136 Idaho 781, 786, 41 P.3d 209, 215 (2002) (citations omitted). Statutes and rules must be construed as a whole. *Verska v. Saint Alphonsus RMC,* 151 Idaho 889, 893, 265 P.3d 502, 506 (2011); *Idaho Power v. Idaho PUC,* 102 Idaho 744, 754, 630 P.2d 442, 452 (1981) (construing PURPA statutes).

It is the Commission that is tasked with implementing PURPA. It is the Commission that approves all PURPA contracts - including the terms of such contracts. **Order** No. 15746, 38 P.U.R. 4th 352 (Idaho 1980). It is also the Commission that sets and approves the avoided cost rates calculated at either the time of delivery or at the time the contract or obligation is incurred. 18 C.F.R. § 292.304(d)(2)(i-ii). *Rosebud II,* 128 Idaho at 613, 917 P.2d at 770. The PURPA regulations also address factors to be considered in determining avoided costs. In setting avoided cost rates, the Commission is to consider "the terms of any contract or other legally enforceable obligation, including the duration of the obligation, the termination notice requirement and sanctions for non-compliance." 18 C.F.R. § 92.304(e)(2)(iii) (emphasis added). Because the Commission must consider contract terms in calculating avoided cost rates especially the length of the contract - we find that setting the length of the contract is a necessary requirement that falls to the Commission. This is not to say that all contracts must be of the same duration. Indeed, as set out above, neither Clearwater nor Simplot has had a contract with a 20-year term. FERC recognizes that there may be instances that would justify a contract for the delivery of power "for a one year period." 45 Fed.Reg. at 12,226. In addition, our final **Order** recognizes that there may be instances where a particular IRP-based PURPA contract is longer than the standard two years. **Order** No. **33357** at 26. Consequently, Clearwater and Simplot's attempt to paraphrase FERC regulations to their advantage is unavailing. It is the Commission's responsibility to set the length of IRP-based PURPA contracts.

B. THE LENGTH OFIRP CONTRACTS

*13 1. The Length of 20-Year Contracts is Unreasonable. The Petitioners next assert that the FERC regulations require "long-term, fixed-price contracts." Petition at 9 (emphasis added). They urge the Commission to continue to use the 20-year contract as the standard IRP contract, or adopt an "alternative proposal of a 20-year contract with an update to energy prices ... in contract year 10." Petition at 4, 5, 15.

The Petitioners assert they are entitled to long-term PURPA contracts "to encourage the sort of energy production required by PURPA." Petition at 9. They rely on FERC's **Order** No. 69 that notes QFs have a "need for certainty with regard to return on investment in new technologies." *Id.* at 9-10, *quoting* 45 Fed.Reg. at 12,224 (1980); Tr. at 776. Their witness Dr. Reading testified that IRP-based PURPA contracts of five years or less would not provide a sufficient revenue stream for QFs to finance their projects or become economically viable. Tr. at 777-79. He indicated that the length of the QF contract is related to "the ability [of the QF] to obtain funds in **order** to build [the QF] project." Tr. at 785.

The Utilities respond that there is nothing in PURPA or its implementing regulations that specify an exact contract length. Answer at 4. They further note the Commission found it was uncontested that "FERC regulations do not dictate a specific number of years or establish a time period for PURPA contracts." *Id., quoting* **Order** No. **33357** at 12; Tr. at 589. They assert that the Commission relied upon precedents from our Supreme Court and other federal courts that held the Commission has the discretion in implementing PURPA to set the length of such contracts. *Id, citing* **Order** No. **33357** at 2-3, 10, 12, 16, 21-22.

Commission Findings: Based upon our review of the record, the PURPA regulations and our prior **Orders**, we affirm our finding in final **Order** No. **33357** that PURPA and its implementing regulations do not require a specific number of years or establish a certain time period for PURPA contracts. **Order** No. **33357** at 12. The Petitioners have not directed our attention to any specific contract length requirement in the PURPA regulations. In addition, our review of **Order** No. 69 reveals that the phrase "long-term contract" appears only twice in the 24 pages of the Federal Register and was not further defined. *See* 45 Fed.Reg. at 12,214. Our findings are supported by substantial evidence.

***14** First, we are unpersuaded by Dr. Reading's testimony that long-term contracts are needed to finance Clearwater's or Simplot's existing QF projects. Neither Clearwater nor Simplot has had a 20-year contract for their existing facilities during the 37 years for which PURPA has been in effect. They have provided no explanation why they need 20-year contracts for their facilities. Moreover, their existing facilities cannot reasonably be considered "new technologies" as referenced by FERC.

We specifically note that Clearwater recently entered into a non-PURPA agreement for the output of its existing facilities until 2021. Thus, Clearwater's existing facilities are contractually bound in a non-PURPA contract until 2021 and are not subject to **Order** No. **33357** for six years. The predecessors of Clearwater and Avista executed their first power purchase contract in 1984 for 10 years. **Order** No. 23858, *Washington Water Power,* 126 P.U.R. 4th 61 (1991). Simplot began selling its power to Idaho Power in 1986 and entered its first long-term PURPA contract (five years) with Idaho Power in 1991. **Order** No. 23552, 1991 WL 11858077 (Idaho PUC). The Petitioners did not seek 20-year contracts in the past and have not persuaded us on reconsideration that 20-year contracts for their existing facilities are needed now. Indeed, Rocky Mountain's witness Mr. Clements testified that all of its cogeneration contracts are for a period of one year. Tr. at 476-77.

Also, the Petitioners' contemplation of new PURPA projects does not persuade us to retain 20-year contracts for several reasons. First, we find the Petitioners' interests in developing new PURPA facilities are speculative and undefined. Other than the possible location, neither Petitioner definitively identified any relevant characteristics of the future projects on which they premise their argument - for example, nowhere does the record contain any information concerning the exact size of any future QF facility nor the proposed operation date. In particular, Clearwater and Avista have been having discussions about such a facility for more than five years. Tr. at 771. While Simplot has asked for indicative pricing for a cogeneration facility up to 25 MW at its new Caldwell facility, we are unaware of any subsequent progress. Tr. at 769. While a QF is entitled to a PURPA contract or a legally enforceable obligation, its offer to sell power to a utility must be firm, binding, and unconditional. **Order** No. 32974; 310 P.U.R. 4th 304 (2014); *Whitehall Wind v. Montana Public Service Commission,* 347 P.3d 1277 (Mont. 2015); *A. W. Brown,* 121 Idaho 818, 828 P.2d at 847.

***15** Second, the Commission found that the standard IRP-based contract of two years was not an absolute term. In particular, the Commission recognized there may be justification for IRP-based contracts in excess of two years. **Order** No. **33357** at 26. Both Avista and Idaho Power have tariff schedules approved by this Commission (Nos. 62 and 73, respectively) that specify the PURPA negotiation process for obtaining a proposed PURPA contract. QFs are certainly free to seek longer contracts if justified on a case-by-case basis. Consequently, at this juncture the Petitioners are not foreclosed from seeking longer contracts for their tentative projects. **Order** No. **33357** at 28; *citing* Tr. at 876, 881.

Third, the Commission found that any asserted need for 20-year contracts was mitigated by the "must purchase" provision of PURPA. **Order** No. **33357** at 23; 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a). "PURPA's 'must purchase' provision requires the utility to continue to purchase the QF's power." **Order** No. **33357** at 25. As long as the projects continue to offer power to utilities, utilities must continue to purchase such power under PURPA. And as long as PURPA remains the law, the ability for QFs to earn a return remains. The shortening of contract length is not intended to inhibit a QF's ability to recover its investment. Rather the shortening of contract length functions as a means of ensuring that avoided costs remain "just and reasonable to the electric consumer of the electric utility and in the public interest" (16 U.S.C. § 824a-3(b)(l)) and serves "to maintain a more accurate reflection of the actual costs avoided by the utility over the long-term." **Order** No. **33357** at 23.

Fourth, the Commission concluded that it was unreasonable to continue 20-year IRPbased PURPA contracts when utilities have no need for additional capacity. *See City of Ketchikan, Alaska,* 94 FERC ¶ 61,293 at 62,061 (2001) ("there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements" and "there is no obligation under PURPA for a utility to enter contracts to make purchases which would result in rates which are not 'just and reasonable to electric consumers of the electric utility and in the public interest' or which exceed 'the incremental cost to the electric utility of alternative energy.'"). The Commission found that both Idaho Power and PacifiCorp presented persuasive evidence of capacity surpluses. More specifically, the Commission found that these "two utilities have demonstrated that their supply of PURPA and non-PURPA power exceeds their current average loads." **Order** No. **33357** at

EXHIBIT A

24, *citing* Tr. at 111, 117, 931. Idaho Power's senior vice president testified that Idaho Power's PURPA and non-PURPA renewable resources (approximately 1,297 MW) equaled about 40% of its 2014 system peak-load and was equal to about 120% of it 2014 minimum system load. **Order** No. **33357** at 13, citing Tr. at 111, 177; Exh. 11 at 2. She testified it was unreasonable for Idaho Power to enter into long-term, fixedrate contracts when the Company does not need additional generation. *Id., citing* Tr. at 117, 119.

*16 Rocky Mountain's witness also testified his company has no need for additional generation until 2028. **Order** No. **33357** at 16, *citing* Tr. at 429. The Commission found that if all the proposed IRP-based contracts for Rocky Mountain were to become operational, then the utility's existing and proposed PURPA contracts would be enough to supply 108% of PacifiCorp's average retail load and 275% of its minimum retail load in Idaho 2014. **Order** No. **33357** at 16, *citing* Tr. at 427. The Commission found that the abundance of PURPA generation extends the utilities' capacity surpluses to 2024 for Idaho Power and 2028 for PacifiCorp." *Id.* at 24.[5] We find these statistics persuasive that 20-year contracts are unjust and contrary to the public interest.

Fifth, the Commission found it unreasonable to continue to authorize 20-year contracts given the proposition that avoided cost rates for IRP projects are declining. **Order** No. **33357** at 22, *citing* Tr. at 260-61; 372; 630-31; 642. Continuing to allow QFs to lock in fixedrate contracts for 20 years "will "overestimate' future avoided cost rates collected from the utilities' ratepayers. Because of the 20-year term of the current IRP-based contracts, this 'overestimation' will become more significant over the [20-year] duration of the contract." *Id.* at 23. Given the projected decline in avoided costs, the Commission found and we affirm on reconsideration that 20-year contracts will result in unjust and unreasonable rates for utility ratepayers and are no longer in the public interest. 16 U.S.C. § 824a-3(b)(l).[6] Thus, substantial and competent evidence supports our conclusions that 20-year contracts will result in long-term avoided cost rates that exceed the utility's incremental costs, thus running afoul of the law. *Id.* at 824a-3(b).

*17 2. <u>The Petitioners' 20-Year Alternative</u>. The Petitioners also objected to the Commission's rejection of their alternative proposal to maintain the 20-year contract but adjust the energy rate. On reconsideration, they propose a different 20-year alternative where the Commission could "re-price the energy component of new contracts in year 10 of the contract while leaving the capacity rate fixed for the entire 20-year term." Petition at 4, 5.

Commission Findings: First, we observe that the Petitioners' alternative proposal on reconsideration is at odds with what they actually proposed in their testimony at hearing. At the technical hearing, Dr. Reading recommended that:

> The Commission maintain a 20-year contract length with the capacity component of the rate fixed for the entire 20-year term. However, as a compromise, the <u>energy portion of the rate would only be fixed the first 10 years of the contract. After the first 10 years, the energy component would be recalculated each year</u> adhering to the Commission-approved method for the remaining term of the contract.

Tr. at 842 (emphasis added); **Order** No. **33357** at 23. In other words, the energy rate would be adjusted annually in each of the last ten years of the contract. The Petitioners either mischaracterized their alternative proposed at hearing or now on reconsideration advance a different 20-year alternative, one offered by the Idaho Conservation League/Sierra Club's witness, Mr. Beach. At hearing, he suggested that the Commission "make a single adjustment in the 11th year of a 20-year contract." **Order** No. **33357** at 23, *citing* Tr. at 702. Once reset, the energy rate "for Years 11-20 would continue to be fixed." *Id.*

We find the Petitioners' new alternative offered on reconsideration suffers from the same defect we previously identified in **Order** No. **33357** and outlined above. "An adjustable rate contract runs the risk of violating FERC regulations that mandate a 'fixed rate' at the time of contracting." **Order** No. **33357** at 24. Further, as long-term avoided cost rates continue to decline, contracts of 20 years will "'overestimate [the]' future avoided costs collected from the utilities' ratepayers." **Order** No. **33357** at 23. This ""overestimation" of future avoided costs will become more significant over the duration of the 20-year alternative proposed by the Petitioners on reconsideration. *Id.* The Petitioners' proposed alternative to adjust energy rates a single time at the mid-point of a 20-year contract does not mitigate our concerns. Finally, "the same result can be accomplished through successive short-term contracts" without the risk of violating FERC regulations or unreasonably burdening customers. *Id.*

*18 Consequently, we affirm our decisions and findings set out in **Order** No. **33357**. There is substantial and competent evidence to support our findings that two-year standard IRP-based contracts are fair and reasonable, absent circumstances that would justify an exemption to the standard length.

C. THE QF IS PROVIDED A CAPACITY RATE AND THE CAPACITY ADJUSTMENT DOES NOT BIND FUTURE COMMISSIONS

In their Petition for Reconsideration, Clearwater and Simplot insist that the two-year contract does not provide QFs with a capacity rate, and that the Commission's capacity adjustment is legally defective. The Petitioners maintain these "errors" caused by the two-year contract and the capacity adjustment justify the return to 20-year contracts or their alternative proposal that re-prices avoided cost energy rates in the middle of the 20-year contract. Petition at 12-15.

1. <u>The Two-Year Contract Provides a Capacity Rate</u>. The Petitioners acknowledge the two-year IRP contract allows for short-term, fixed-price compensation for energy but they argue the **Order** provides "<u>no price at all for capacity</u> and thereby deprives the QF of the right to sell capacity." Petition at 12 (emphasis added). They insist that a QF is deprived of a 'fixed contract price for its energy *and* capacity at the outset of its obligation' because ... a two-year contract will not provide a price for capacity that is fixed at this time." *Id.* at 12 (italics original and citations omitted).

The Utilities offer three arguments in response. First, the Utilities assert the Petitioners have misconstrued the Commission's final **Order** No. **33357**. They maintain that the **Order** was not intended to establish avoided cost rates. "[The **Order**] is limited to addressing the maximum contract length." Answer at 7. Actual avoided cost rates, for both avoided energy and avoided capacity, are established in other Commission **Orders** and through the Commission's approval of individual contracts.

Second, the Utilities maintain that the Petitioners' allegation that **Order** No. **33357** does not set a capacity rate, is really an impermissible collateral attack on the Commission's prior **Orders** that do establish avoided cost rates for both capacity and energy in IRP-based contracts. *Idaho Code* § 61-625 (final and conclusive **orders** of the Commission "shall not be attacked collaterally"). The Utilities insist that avoided cost rates for capacity (or energy) are simply not relevant to this proceeding. *Id.* at 7.

Third, the Utilities maintain that when a utility has a capacity surplus, then the "capacity component of the avoided cost price [is] zero. The <u>capacity price is not absent, ... it is set at zero because the utility is capacity sufficient</u>." *Id.* at 8 (emphasis added). The Utilities explain that a QF is only entitled to capacity rates when the utility has a need for additional generation or firm power purchases - i.e., when a QF contributes capacity to a utility with a capacity deficiency, then the avoided cost rates for the QF "will include both avoided energy and capacity [rates]." *Id., citing* Tr. at 276.

***19** The Utilities conclude that the Commission's capacity adjustment was intended to recognize that the QF will be eligible to receive capacity rates when the utility is no longer capacity deficient. They insist this is a benefit to QFs in that it allows a QF to establish a right to capacity payments at the time the initial IRP-based contract is signed or the obligation is incurred. Answer at 8. They quote from the Commission's **Order**:

> As long as the QF renews its contract and continuously sells power to the utility, the QF is entitled to capacity [payments] based on the capacity deficiency date established at the time of [the QF's] initial contract.

Order No. **33357** at 25-26. They maintain the primary difference between the Commission's previously established 20-year term and the two-year contract term established in **Order** No. **33357**, is that the avoided cost rates "are refreshed at each two-year contract interval, rather than being erroneously estimated and locked-in over 20 years." Answer at 8.

Commission Findings: We are unpersuaded by the Petitioners' capacity adjustment arguments for several reasons. First, the capacity adjustment does not apply to Petitioners' existing facilities. Because the existing Clearwater and Simplot facilities already contribute capacity to Avista and Idaho Power respectively, they both currently receive, and remain eligible to receive, capacity payments when their existing contracts are renegotiated and renewed. Indeed, the Petitioners concede that renewal contracts for their existing QF facilities would continue to receive compensation for capacity under the

Commission's **Order** No. **33357**. Petition at 4.

Second, the Petitioners also misconstrue the mechanics of the capacity adjustment as they relate to any new, unbuilt future QF projects. If the utility has a capacity surplus, then a first-time QF entering into its initial two-year IRP contract is not eligible to receive any payment for capacity. However, if the purchasing utility has a capacity deficit in the initial or subsequent two-year contract, then the QF is eligible to receive capacity payments from that point forward. Both FERC and this Commission have a long-standing practice of allowing QFs to obtain capacity payments only when the utility is or

> 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.

Order No. **33357** at 25, *quoting* **Order** No. 32697 at 21; Tr. at 586-87. Thus, if a utility has a capacity surplus during the entire two years of an IRP-based contract, a QF is not eligible to receive a capacity payment. In practical terms, the avoided cost capacity rate in this example is zero.

***20** As FERC stated in its **Order** No. 69, avoided cost rates need not include capacity costs unless the QF purchase will permit the utility to avoid building or buying future capacity. **Order** No. 69, 45 Fed.Reg. at 12,225-26. "[C]apacity payments can only be required when the availability of capacity from a [QF] actually permits the purchasing utility to reduce its need to provide capacity by deferring the construction of new plant or commitments to firm power purchase contracts." *Id.* While the utility may have an obligation under PURPA to purchase power from a QF, "that obligation does not require a utility to pay for capacity that it does not need." *City of Ketchikan,* 94 FERC ¶ 61,293 at *6.

2. <u>Forecasted Capacity Rates</u>. The Petitioners also argue that PURPA's implementing regulations entitle them to a forecasted capacity rate when they enter into their contact/obligation. For example, if Clearwater or Simplot enters into a contract for their unbuilt and speculative facilities to be effective in 2015 but the utility has a capacity surplus until 2024, the Petitioners argue they are entitled to a future capacity rate for 2024, when the utility is capacity deficient. They allege that this lack of a forecasted capacity rate calculated at the time they enter into their contract "is obviously not what FERC had in mind when it stated its [PURPA regulation] provides each QF with a 'capacity credit' through [sic] in a 'fixed contract price ... at the outset of its obligation' that provides 'certainty with regard to return on investment."' Petition at 14, *citing* 45 Fed.Reg. at 12,224. They assert the capacity adjustment does not comply with section 292.304(b) which "requires that the QF be provided a fixed price to sell that capacity at the time of commencement of the [contract or] obligation - not a rate calculated ... several years from now." Petition at 14.

Commission Findings: We find the Petitioners misunderstand our **Order** and FERC regulations. The regulations provide that a QF has the option to either provide energy or capacity as available, or at avoided cost rates calculated "over [the] specified term." 18 C.F.R. § 292.304(d)(1), (2). If the QF chooses to sell power to the utility over a specified term, the QF may have the rates calculated <u>for the term</u> at either "the time of delivery; or ... at the time the obligation is incurred." 18 C.F.R. § 292.304(d)(2)(I-II). In **Order** No. **33357**, we determined that "the specified term" for new standard IRP-based contracts is two years. Thus, Clearwater and Simplot are entitled to receive avoided cost capacity rates for <u>the specified term</u> calculated at either the time of delivery or at the time they enter into their contract/obligation.

***21** We also directed the Utilities to establish their capacity deficiency date when a QF's initial IRP-based contract is signed. **Order** No. **33357** at 25-26. This capacity adjustment mechanism recognizes that if a QF continues to provide energy to a utility through when the utility would otherwise experience a capacity deficiency, the QF will be paid for its capacity contribution. But until a QF enters into a contract during which that capacity deficit date occurs, the avoided cost capacity rate is zero.

As Mr. Wenner opined, a QF "is entitled to receive [capacity] rates based on the capacity cost that the utility can avoid as a result of its obtaining capacity from the [QF]." Tr. at 586, *quoting* 45 Fed.Reg. at 12,225. A capacity rate calculated at the start of each specified term rather than upon a QF's initial contract, is a truer reflection of the utility's avoided cost for capacity. The capacity adjustment mechanism thus ensures the QF receives the full avoided cost of the utility, consistent with FERC regulations.

Notably, FERC comments drafted at the time it was issuing its PURPA regulations provided:
[FERC] recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which, by definition, is based on estimation and forecasting of future occurrences.

...

Accordingly, [FERC] supports the recommendation made in the Staff Discussion Paper that it should leave to the States and nonregulated utilities "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from [QFs] reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

45 Fed.Reg. at 12,226.

As set out in **Order** No. **33357**, Idaho has been very successful in encouraging the development of renewal QF power. Our changes in this docket are simply intended to ensure the utility is not paying more than its actual avoided costs when purchasing QF power.

3. <u>The Capacity Adjustment does not Bind Future Commissions</u>. Simplot and Clearwater also argue that the Commission's capacity adjustment suffers from legal defects. They argue that this Commission cannot bind a future Commission to a capacity deficiency date at any particular point in a hypothetical future PURPA contract. Petition at 13. In other words, they allege the present Commission cannot set a future capacity deficiency date in a future 2023 contract. They insist the QFs cannot reasonably rely on the Commission's non-binding decision to support the QF's right to sell its capacity in a hypothetical 2023 contract. Petition at 14. They argue in a footnote that the ""reserved powers doctrine" limits the ability of the Commission to bind a future Commission. *See* Petition at footnote 1. The Utilities do not respond to this specific argument.

22** ***Commission Findings: Under the reserved powers doctrine, "a state government may not contract away "an essential attribute of its sovereignty." *U.S. v. Winstar Corp.*, 518 U.S. 839, 888 (1996), *citing United States Trust Co. v. New Jersey*, 431 U.S. 1, 23 (1977). Such "essential attributes" of state sovereignty include the power of eminent domain, and the power to police. This "power to police" is commonly referred to as a state's police power. In Idaho, the Commission exercises legislative police power when setting rates. *Coeur d'Alene Dairy Queen v. State insurance Fund*, 154 Idaho 379, 385, 299 P.3d 186, 192 (2013); *Idaho Power & Light Co. v. Blomquist*, 26 Idaho 222, 258, 141 P. 1083, 1094 (1914). The Commission's regulation of utility rates set by private contract is subject to such police power. *Agricultural Products Corp. v. Utah Power & Light Co.*, 98 Idaho 23, 29, 557 P.2d 617, 623 (1976).[7]

The related doctrine of "unmistakability" provides, "absent an 'unmistakable' provision to the contrary, 'contractual arrangements, including those to which a sovereign itself is a party, remain subject to subsequent legislation by the sovereign."' *Winstar*, 518 U.S. at 877, *citing Bowen v. Public Agencies Opposed to Social Security Entrapment, All* U.S. 41, 52 (1986) (internal quotations omitted).

We believe neither doctrine applies in this PURPA case. First, the Commission's capacity adjustment is not a "contract" where the Commission is a party to the contract. The capacity adjustment is also not a "rate." It is a mechanism used to determine when a new QF in an IRP contract is eligible to receive capacity payments. It is always true that the Commission can exercise its authority to change a ruling in a subsequent decision, just as a state legislature can change a law. Our Supreme Court has held on numerous occasions that the Commission is not rigorously bound by the doctrine of *stare decisis*. *Idaho Power*, 155 Idaho at 1286, 316 P.3d at 788; *McNeal-Idaho PUC*, 142 Idaho 685, 690, 132 P.3d 442, 447 (2006). However, when the Commission departs from a previously-established policy, it must explain its departure from prior rulings so that a reviewing court can determine that the decision to change is not arbitrary or capricious. *Inter mountain Gas Co. v. Idaho PUC*, 97 Idaho 113, 119, 540 P.2d 775, 781 (1975). So long as the Commission adequately explains its departure, "**orders** based upon positions substantially different than those taken in previous proceedings can be upheld." *Id.*

***23** Such authority does not diminish the "legal effect" of the Commission's decision, from any perspective. The determinations and rulings in a final **Order** are binding on the affected utilities until they are changed or rescinded in the future. *Idaho Code* §§ 61-406 (every utility "shall obey and comply with each and every **order**, decision, direction, rule or regulation ..."). To the extent Clearwater/Simplot mean to assert that the Commission's decision has no ""practical effect" from a QF's perspective, because a future Commission could enter a contrary decision, the same could be said of any existing QF contract, any Commission decision, or indeed any law. Thus, we reject the Petitioners claims of a legal defect.

D. THE CAPACITY ADJUSTMENT IS SUPPORTED BY SUBSTANTIAL EVIDENCE IN THE RECORD

Finally, the Petitioners assert that the Commission's capacity adjustment was not advocated by any party and therefore falls outside the record. They allege that no party discussed this idea in testimony and no party has had an opportunity to address it. They insist that the "Commission's findings and conclusions must be made upon the record developed before it, and that when an administrative agency strays from the records its findings are not supportable on review." Petition at 16.

The Utilities assert that this argument is without merit. They note that the Commission received extensive testimony from the Petitioners' witness Dr. Reading and from the Sierra Club's witness Mr. Wenner regarding the need to compensate QFs for capacity. Answer at 9-10, *citing* Tr. at 773-79, 583-601. The Utilities also argue that the Commission's resolution of disputed issues is not so strictly limited to relief that "was exactly proposed or suggested by the parties. The Commission is free to act within it authority and discretion, based on the evidence before it." *Id.*

Commission Findings: Despite the Petitioners' argument to the contrary, the Commission's capacity adjustment was specifically designed to ensure that the reduction in the standard-length IRP contract from 20 years to two years does not permit Utilities to avoid their obligation to make capacity payments to QFs "in the first year the utility has an identified [capacity] deficiency." Tr. at 701. As Mr. Wenner explained, FERC's PURPA regulations require QFs to be paid for capacity when the QF is providing capacity that enables the utility to avoid or forego the construction of new generating facilities or the purchase of firm power. *Id,* at 587, Quoting from FERC's **Order** No. 69, Mr. Wenner testified that a QF "is entitled to receive [capacity] rates based on the capacity cost that the utility can avoid as a result of its obtaining capacity from the [QF]." Tr. at 586, *quoting* 45 Fed.Reg. at 12,225. He insisted that if QF contracts are limited to two years, then "that power cannot be counted on to be available after two years...." Tr. at 587. The Petitioners' witness Dr. Reading also objected to the reduction in the length of IRP contracts. He opined that if IRP-based contracts are shortened to five or fewer years, the QF will not be able to cause the utility to avoid future capacity additions. Tr. at 777, 778-79. He argued that the shortened contract length is designed to deprive capacity payments to the QF. *Id.* at 786.

***24** Given these concerns about capacity and capacity payments, the Commission fashioned its capacity adjustment to remedy these concerns expressed by the parties. Consistent with FERC regulations and our **Orders**, a utility is required to pay for capacity contributed by the QF when the utility no longer has a capacity surplus. **Order** No. **33357** at 25-26, *citing* **Order** No. 32697 at 21. While the "must purchase" provision requires utilities to purchase capacity and energy from a QF, "that obligation does not require a utility to pay for capacity that it does not need." *City of Ketchikan,* 94 FERC ¶ 61,293 at *6. When a QF enters into its initial contract/obligation with the utility, the capacity adjustment entitles the QF to know the exact date when it will be eligible to receive capacity payments as long as the QF continues to contribute to the utility resource stack. Thus, the Commission created the adjustment in conjunction with the standard two-year term for IRP-based contracts to prevent utilities from circumventing their obligations to pay for capacity when the utility becomes capacity deficient.

The Commission's capacity adjustment is based upon ample evidence in the record offered by the Petitioners and other parties, and comports with FERC regulations requiring utilities to make avoided cost capacity payments to the QF at times when the utility is capacity deficient. The Idaho Supreme Court will uphold the Commission's findings of fact if they are supported by substantial, competent evidence. *Idaho Power,* 755 Idaho at 787, 316 P.3d at 1285; *Rosebud II,* 128 Idaho at 618, 917 P.2d at 775. In both **Order** No. **33357** and here, the Commission has explained its reasoning used to reach its conclusions based on substantial and competent evidence from the record before it.

Given the totality of the evidence in the record, we affirm our findings in final **Order** No. **33357** that it is reasonable and consistent with PURPA that the standard IRP contract be reduced from 20 years to two years. It is uncontested that utilities do not need additional generating capacity and that PURPA and non-PURPA generation exceeds Idaho Power's and Rocky

Mountain's minimum average loads. More importantly, given the undisputed evidence that avoided costs are decreasing, retaining fixed rates for 20 years would violate PURPA's Section 210(b) mandate that avoided costs rates shall not exceed a utility's avoided costs. We find that the Petitioners' alternative proposal to adjust energy rates one time in the middle of a 20-year contract is not consistent with PURPA's intent or FERC's regulations. Consequently, the Commission denies Simplot's and Clearwater's request to retain 20-year terms for IRP-based contracts.

ORDER

*25 IT IS HEREBY **ORDERED** that Clearwater's and Simplot's request to amend final **Order** No. **33357** is denied. The Commission declines their request to continue a 20-year term for IRP-based contracts or to adopt their alternative proposal on reconsideration to adjust energy rates one time at the mid-point of a 20-year contract.

IT IS FURTHER **ORDERED** that the Petitioners' other issues raised in their Petition for Reconsideration are dismissed as set out in the body of this **Order**.

THIS IS A FINAL **ORDER** ON RECONSIDERATION. Any party aggrieved by this final **Order** on Reconsideration or other final or interlocutory **Orders** previously issued in this Case Nos. IPC-E-15-01, AVU-E-15-01, and PAC-E-15-03 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 5 th day of November 2015.

PAUL KJELLANDER, PRESIDENT

Commissioner Smith did not participate in this case

MARSHA H. SMITH, COMMISSIONER

KRISTINE RAPER, COMMISSIONER

ATTEST:

Jean D. Jewell

Commission Secretary

Footnotes

1 Other types of PURPA generating facilities include: cogeneration (such as Clearwater and Simplot); geothermal; hydro (both year-round and seasonal); landfill gas; and bio-gas facilities.

2 *See supra* text on page 4 explaining capacity and capacity rates/payments.

3 The Commission approves all PURPA contracts and other power sales agreements by issuing final **orders**. **Order** No. 32802 at 1 l(and citations therein). *Idaho Code* § 61-502.

4 The Commission's procedural Rule 263 allows the Commission to take official notice of its own **orders** and notices. IDAPA 31.01.01.263.01.a. We take official notice of our prior **Orders** approving the length of the Petitioners' PURPA contracts.

5 Avista has a capacity surplus until 2020. **Order** No. 33014 at 3.

6 The Petitioners' reliance on the *Hydrodynamics, Cedar Creek Wind,* and *New York State Electric & Gas* cases is misplaced. These cases are not relevant to the issue of contract length and are factually distinguishable. *Hydrodynamics,* 146 ¶ 61, 193 P. 31 (2014); *Cedar Creek Wind,* 137 FERC ¶ 61,006, P. 32 (2011); *New York State Electric & Gas Corp.,* 71 FERC ¶ 61,027, 61,115-16 (1995).

EXHIBIT A

7 The Commission may only interfere with the utility's contract if it finds that a rate is so low or so high as to adversely affect the public interest; "where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory." *Bunker Hill Co. v. Washington Water Power Co.*, 98 Idaho 249, 253, 561 P.2d 391, 395 (1997) (quoting the elements of the Sierra-Mobile Doctrine from *Federal Power Commission v. Sierra Pac. Power Co.*, 350 U.S. 348, 355 (1956).

End of Document

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES 100 KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate rider schedule is available in all territory served by the Company.

APPLICATION

This rate rider schedule is applicable to customers served by a retail rate schedule with metered kWh usage with a cogeneration or small power production facility with a nameplate continuous AC output power rating of 100 kW or less, where the facility's generator(s) and load are located at the same premise, and that otherwise meet qualifying status pursuant to Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to Qualifying Facilities electing to configure their systems as to require partial requirements service from the Company in order to meet their electric requirements.

At the Company's discretion, the monthly purchase rates in this schedule may also be used as a basis to purchase energy from a Qualifying Facility that is not configured for partial requirements service and/or is greater than 100 kW. The terms for such purchase shall be provided in a contract to be approved by the Commission.

Participation under this schedule is subject to the availability of required metering equipment compatible with the customer's retail rate schedule and electrical service configuration. All provisions of the customer's retail rate schedule will continue to apply except as noted below.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by the customer (subject to availability at the premises). The Qualifying Facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Qualifying Facility will be responsible for all incremental costs incurred to accommodate such an arrangement.

SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet its supplemental or interruptible electric requirements will be priced at the customer's retail rate schedule.

PURCHASE OF EXCESS GENERATION

The Company shall issue a credit on the customer's monthly bill for the monthly Excess Generation, based on the relevant monthly purchase rates, which are based on avoided energy costs and shall be updated annually. Purchase rates are provided for Firm Power and Non-Firm Power for the summer and winter billing cycles. Firm Power is only relevant to the summer billing cycles.

For customers served under a time-of-use retail rate schedule, purchase rates are provided for the relevant on-peak and off-peak hours. For residential customers served under a non-time-of-use rate, or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on a 12 p.m. to 7 p.m. on-peak rate. For non-residential customers served under a non-time-of-use rate or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on an 11 a.m. to 9 p.m. on-peak rate. Unless specified in this schedule, Excess Generation during a super-on-peak or shoulder-peak time period in a retail rate will be purchased at the on-peak purchase rate, while Excess Generation during a super-off-peak period will be purchased at the off-peak purchase rate.

Purchase of Excess Generation (Con't)

For customers served under a 9 a.m. to 9 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.211	2.136	2.677	2.219
Winter Billing Cycles (November - April)	2.188	2.203	2.188	2.203

[1] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

For customers served under a 12 p.m. to 7 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.172	2.160	2.971	2.227
Winter Billing Cycles (November - April)	2.173	2.204	2.173	2.204

[1] On-Peak Periods: 12 p.m. to 7 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

For customers served under an 11 a.m. to 9 p.m. on-peak time-of-use rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.202	2.146	2.761	2.222
Winter Billing Cycles (November - April)	2.180	2.205	2.180	2.205

[1] On-Peak Periods: 11 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

CONTRACT PERIOD

As provided for in any Supply /Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service: Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any Excess Generation (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

2. Qualifying Facility (QF): A cogeneration or small power production facility which meets the requirements under 18 CFR, Chapter I, Part 292, Subpart B of the Federal energy Regulatory Commission regulations.

3. Excess Generation: Equals the customer's generation (kWh) in excess of their load at any point in time as metered by the Company. Excess Generation is computed for on-peak and off-peak billing periods.

4. Special Service(s): The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

5. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

6. Firm Power: Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

7. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.

METERING

Customers served under this rate schedule will require a bi-directional meter that will register and accumulate the net electrical requirements of the customer. The bi-directional meter shall be provided at no additional cost to the customer. A bi-directional meter may not be required if the generating capacity of the Qualifying Facility is less than 20% of the customer's lowest billing demand over the12 months prior to requesting enrollment in Schedule EPR-2, or as otherwise determined by the Company through available information, or if the customer agrees that they do not intend to be compensated for any Excess Generation.

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES 100 KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate rider schedule is available in all territory served by the Company.

APPLICATION

This rate rider schedule is applicable to customers served by a retail rate schedule with metered kWh usage with a cogeneration or small power production facility with a nameplate continuous AC output power rating of 100 kW or less, where the facility's generator(s) and load are located at the same premise, and that otherwise meet qualifying status pursuant to Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to Qualifying Facilities electing to configure their systems as to require partial requirements service from the Company in order to meet their electric requirements.

At the Company's discretion, the monthly purchase rates in this schedule may also be used as a basis to purchase energy from a Qualifying Facility that is not configured for partial requirements service and/or is greater than 100 kW. The terms for such purchase shall be provided in a contract to be approved by the Commission, which shall not exceed two years.

Participation under this schedule is subject to the availability of required metering equipment compatible with the customer's retail rate schedule and electrical service configuration. All provisions of the customer's retail rate schedule will continue to apply except as noted below.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by the customer (subject to availability at the premises). The Qualifying Facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Qualifying Facility will be responsible for all incremental costs incurred to accommodate such an arrangement.

SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet its supplemental or interruptible electric requirements will be priced at the customer's retail rate schedule.

PURCHASE OF EXCESS GENERATION

The Company shall issue a credit on the customer's monthly bill for the monthly Excess Generation, based on the relevant monthly purchase rates, which are based on avoided energy costs and shall be updated annually. Purchase rates are provided for Firm Power and Non-Firm Power for the summer and winter billing cycles. Firm Power is only relevant to the summer billing cycles.

For customers served under a time-of-use retail rate schedule, purchase rates are provided for the relevant on-peak and off-peak hours. For residential customers served under a non-time-of-use rate, or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on a 12 p.m. to 7 p.m. on-peak rate. For non-residential customers served under a non-time-of-use rate or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on an 11 a.m. to 9 p.m. on-peak rate. Unless specified in this schedule, Excess Generation during a super-on-peak or shoulder-peak time period in a retail rate will be purchased at the on-peak purchase rate, while Excess Generation during a super-off-peak period will be purchased at the off-peak purchase rate.

Purchase of Excess Generation (Con't)

For customers served under a 9 a.m. to 9 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.211~~2.959~~	2.136~~2.892~~	2.677~~3.705~~	2.219~~3.031~~
Winter Billing Cycles (November - April)	2.188~~2.927~~	2.203~~2.844~~	2.188~~2.927~~	2.203~~2.844~~

[1] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

For customers served under a 12 p.m. to 7 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.172~~2.989~~	2.160~~2.897~~	2.971~~4.297~~	2.227~~3.009~~
Winter Billing Cycles (November - April)	2.173~~3.040~~	2.204~~2.831~~	2.173~~3.040~~	2.204~~2.831~~

[1] On-Peak Periods: 12 p.m. to 7 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

For customers served under an 11 a.m. to 9 p.m. on-peak time-of-use rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.202~~2.982~~	2.146~~2.888~~	2.761~~3.876~~	2.222~~3.015~~
Winter Billing Cycles (November - April)	2.180~~2.926~~	2.205~~2.852~~	2.180~~2.926~~	2.205~~2.852~~

[1] On-Peak Periods: 11 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

CONTRACT PERIOD

As provided for in any Supply /Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service: Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any Excess Generation (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

2. Qualifying Facility (QF): A cogeneration or small power production facility which meets the requirements under 18 CFR, Chapter I, Part 292, Subpart B of the Federal energy Regulatory Commission regulations.

3. Excess Generation: Equals the customer's generation (kWh) in excess of their load at any point in time as metered by the Company. Excess Generation is computed for on-peak and off-peak billing periods.

4. Special Service(s): The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

5. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

6. Firm Power: Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

7. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.

METERING

Customers served under this rate schedule will require a bi-directional meter that will register and accumulate the net electrical requirements of the customer. The bi-directional meter shall be provided at no additional cost to the customer. A bi-directional meter may not be required if the generating capacity of the Qualifying Facility is less than 20% of the customer's lowest billing demand over the12 months prior to requesting enrollment in Schedule EPR-2, or as otherwise determined by the Company through available information, or if the customer agrees that they do not intend to be compensated for any Excess Generation.