BEFORE THE

RECEIVED
2015 APR 23 PM 4:40
IDAHO PUBLIC UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	CASE NO. IPC-E-15-01
IN THE MATTER OF AVISTA CORPORATION'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	CASE NO. AVU-E-15-01
IN THE MATTER OF ROCKY MOUNTAIN POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	CASE NO. PAC-E-15-03

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

APRIL 23, 2015

Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as the Engineering Supervisor.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources Energy Division from 1983 to 1994. In 1988, I became licensed in Idaho as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. My duties at the Commission include analysis of a wide variety of electric and large water utility applications. I have been the lead staff member on all Public Utility Regulatory Policies Act (PURPA) dockets at the Commission since 1994. In addition, I lead the Engineering Section and supervise a staff of engineers and utility analysts.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address the petition of Idaho Power to reduce the maximum contract length for IRP-based (Integrated Resource Plan) PURPA contracts from the current 20 years to two years. I will also address similar requests by Avista and PacifiCorp for reduced contract lengths. In addition, I will make recommendations for maximum contract length for SAR-based (Surrogate Avoided Resource) PURPA contracts, including replacement contracts.

Q. What do you believe is the real issue that needs to be addressed in this case?

A. I believe the real issue is the risk exposure to ratepayers that can occur due to long-term PURPA contracts. Long-term contracts, by themselves, would not necessarily be problematic if the long-term avoided cost rates contained in those contracts fairly represented avoided costs over the entire duration of the contract. Unfortunately, however, I do not believe any avoided cost calculation can prove to remain accurate over a 20-year period. Absent any mechanism to periodically adjust avoided cost rates throughout the term of the contract, shorter contract lengths appear to be one of the only viable and effective ways to reduce the risk exposure to ratepayers.

Q. Why don't you believe avoided cost calculations can prove to remain accurate over a 20-year period?

A. Under the IRP method, avoided cost rates are computed, in large part, using an hourly dispatch model that dispatches generation to meet load in each hour at the lowest possible cost. The dispatch models require extensive information about each of the generation plants, typically throughout the western U.S., as well as long-term forecasts of loads and fuel prices. While forecasts can be prepared and assumptions can be made easily enough, it is extremely unlikely that those forecasts and assumptions will remain accurate over a long period of time. Consequently, it is equally unlikely that the avoided cost rates that emerge from the dispatch models will remain accurate. It is possible that the avoided cost rates will be too high at some times and too low at other times. It is also possible, however, that the avoided cost rates will be too high or too low throughout the entire contract length. Regardless of whether the avoided cost rates are too high or too low, 100 percent of the risk of actual prices deviating from forecasted avoided cost rates is borne by ratepayers and none of the risk is borne by QFs.

Q. Has the Commission Staff taken a position recently on maximum contract length for PURPA contracts?

A. Yes, in Case No. GNR-E-11-03, I recommended that the Commission reduce maximum contract length to five years for contracts containing rates computed under the IRP methodology. This recommendation supported Idaho Power's request in that case.

Q. Did the Commission accept your recommendation?

A. No, the Commission did not. The Commission stated the following in Order No. 32697:

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

Q. The passage from Order No. 32697 you have quoted above reflects the Commission's position less than two and a half years ago. Why do you believe the Commission should consider a different position today?

A. In the short two and a half years since the

Order was issued, Idaho Power has signed agreements for 461 MW of new solar generation,[1] and, as stated in its Petition, has received pricing requests for 885 MW of additional solar generation. In response to Staff production requests, Idaho Power states that it has received additional requests for solar contracts of approximately 120 MW since the filing of this case on January 30, 2015. PacifiCorp has received pricing requests for 275.5 MW of new solar generation according to its Petition. Contrary to what was contemplated in the Order, it would not appear that PURPA development needs further encouragement at this time.

Order No. 32697 suggested that other tools should be used to ensure accurate and up to date avoided cost rates, but I believe there are now few other tools available. Avoided cost rates can be calculated accurately at the beginning of a contract term, but no matter how accurate they may be to start, they are bound to become inaccurate over a 20-year period for a long term contract.

Q. Is the significant increase in the cumulative amount of PURPA power a recent phenomenon?

---

[1] The Commission was recently informed by Idaho Power that four solar contracts representing 141 MW have been terminated for failure to post security.

A. Yes, as shown in Idaho Power's Exhibit No. 1, the total amount of PURPA power began its significant increase from 216 MW in 2008, to an estimate of 2187 MW in 2018.[2] From 1982 to about 2007, Idaho Power had less than 200 MW of PURPA generation, primarily hydro. For approximately the first 25 years, the average size of PURPA projects was only about 2.5 MW.

Q. Has the Commission ever before limited contracts to five years or less?

A. Yes, it has. The Commission's policy with regard to contract length has evolved over the years. From 1980 when PURPA was first implemented in Idaho, through 1987, utilities were obligated to offer QFs up to 35-year contracts. The reason for the 35-year maximum contract length was that 35 years was the amortization period allowed for similar utility-owned facilities. A contract length that matched the project's amortization schedule made financing easier, and in effect, helped encourage QF development.

In 1987 (*See* Case No. U-1500-170, Order No. 21630) the Commission shortened the standard contract

---

[2] Note that the total estimate for 2018 includes 885 of proposed contracts. In addition, it includes 461 MW of signed contracts. The Commission was recently notified that 141 MW of signed contracts have defaulted, and the contracts have been terminated.

length to 20 years reasoning that risk and uncertainty inherent in long-range forecasting increases dramatically with time and that a shorter contract term would reduce that risk. The Commission ruled that contracts longer than 20 years would be available to QFs only upon a persuasive showing of need.

Nine years later, in 1996, the Commission again reexamined the issue of contract length. In Order No. 26576 in Case No. IPC-E-95-9, the Commission further shortened the maximum required contract length from 20 years to five years for projects 1 MW and larger. In 1997, the Commission extended the five-year contract length limitation established for large QFs to smaller than 1 MW QFs as well. (*See* Case No. IPC-E-97-9, Order No. 27111)

In 2002, the Commission increased maximum contract length from 5 years back to 20 years. The Commission explained that when it earlier had reduced maximum contract length to five years, there was an expectation of widespread deregulation, more competitive markets, and greater reliance on short-term market purchases. However, by 2002, the Commission recognized that each of Idaho's regulated electric utilities were constructing or had recently constructed long-term new generation resources. In restoring 20 years as the maximum contract length, the Commission reasoned that a longer contract better coincides with the planned resource life of renewable or cogeneration resources being offered, better reflects the amortization period of generation projects constructed by the utilities themselves and will coincidentally provide a revenue stream that will facilitate the financing of QF projects. (*See* Order No. 29029)

Q. During the approximately five and a half year period when contract length was limited to five years (September, 1996 through May, 2002), weren't very few PURPA contracts signed?

A. Yes, there was only one PURPA contract signed in Idaho during this time frame. However, at the time, the eligibility threshold for published rates was also limited to facilities one megawatt or smaller. In addition, published rates were also quite low at this time, primarily due to low natural gas prices. Furthermore, most PURPA hydro and cogeneration projects had already been developed, while wind, solar and biogas technology had yet to fully develop. The combination of all of these factors, not shortened contract length alone, caused very few PURPA projects to be developed in Idaho during this time period.

Q. But won't a five-year limit on maximum contract length, if approved, limit the ability of projects to obtain financing, thus making extensive project development unlikely?

A. Yes, I agree that development would likely slow considerably, at least under PURPA. However, facilities could still be developed under other mechanisms. For example, if a utility identified a need in its IRP and if certain renewables or cogeneration possessed the characteristics and costs making it part of a preferred portfolio, then the utility could acquire renewables or cogeneration with long-term contracts in response to utility requests for proposal. This was the mechanism employed by Idaho Power in signing power purchase agreements (PPAs) with the Neal Hot Springs and Raft River geothermal projects (35 MW), and the Elkhorn wind project(101 MW). Similarly, Avista secured a PPA for the Palouse wind project in the same way. Finally, PacifiCorp has either signed multiple PPAs or acquired ownership of wind projects in the same manner.

QFs could also sell their output to other utilities outside of Idaho, just as some out of state projects currently sell their output to Idaho utilities. In addition, projects could be developed in Idaho and sell their output to out of state buyers, not as QFs under PURPA, but as Exempt Wholesale Generators. At least one large wind project in eastern Idaho sells its output to Southern California Edison in this fashion. In fact, this is a very common mechanism for project development throughout other parts of the country.

Alternatively, projects could also sign PURPA contracts and replace them every five years (or whatever maximum contract length the Commission decides) as long as PURPA remains in effect.

Q. Do you believe that the Commission should shoulder some responsibility for ensuring contract lengths are long enough to enable QFs to obtain financing?

A. No, not necessarily. Where the Commission desires to boost development of PURPA projects, long-term contracts may accomplish that goal. However, currently, Idaho utilities, particularly Idaho Power, are being inundated with more projects than they need or can accommodate. In Order No. 32697, the Commission stated that it is not the Commission's responsibility to ensure contracts are long enough to enable projects to obtain financing. Because the Commission must also regulate the reasonableness of customer rates and the reliability of power, it is ultimately a matter of policy—how the Commission wishes to weigh its various considerations.

Q. Is a 20-year maximum contract length inconsistent with PURPA's objectives?

A. Yes, it can be. One of the Commission's primary duties under PURPA is to set avoided cost rates that are just and reasonable to customers, in the public interest, and not discriminatory to QFs. Such rates must not exceed incremental costs to the utility. The concern arises when contracts extend for many years and the forecast of avoided cost becomes inaccurate. Long-term contracts based on forecasted rates create greater risks for customers because the rates in the later years are not reflective of avoided costs.

Q. Are there any specific requirements under PURPA regarding contract length?

A. No, FERC's regulations implementing PURPA are silent on contract length. Furthermore, I am not aware of any FERC case or court decision involving a requirement for a minimum contract length.

However, FERC rules do appear to contemplate less than 20 year contracts. Section 292.302 of the FERC rules implementing PURPA, requires utilities to make available information from which avoided costs may be derived. For energy, utilities are required to estimate the energy component of avoided costs by year for the current year and each of the next five years. For capacity, the utility must make available its plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years. Thus, these component forecasts are much less than the 20-year contract.

In Idaho, utilities do not actually submit such information to the Commission because FERC rules permit states to require different information for deriving avoided costs. Nonetheless, I think the mere mention of five year estimates for energy and 10 years for capacity suggests 20 year maximum contract lengths are not necessarily expected.

Q. Are there other reasons why you believe that maximum contract length should be shortened to five years?

A. Yes, there are. When the surrogate avoided resource (SAR) was changed from a coal-fired resource to a gas-fired resource in 1995, fuel became a much larger portion of the avoided cost rate. By comparison, fuel is a far more substantial portion of costs for a gas-fired resource than for a coal-fired resource. In fact, for the gas-fired combined cycle combustion turbine (CCCT) now used as the SAR, fuel represents approximately two thirds of the project costs. The fuel component of costs must be estimated based on 20-year forecasts. As history has demonstrated, it can be extremely difficult to accurately forecast gas prices just a few years into the future, let alone 20 years into the future. Similarly, under the IRP methodology, much of the cost upon which PURPA rates are based is driven by fuel prices. Gas-fired generation is on the margin much of the hours of the year; consequently, electric market prices are frequently closely tied to natural gas prices. A five year contract allows contract rates to be adjusted regularly to more accurately reflect current fuel prices.

Moreover, a fixed price contract is more risky than one in which prices are adjusted frequently. A long-term fixed price could possibly be accurate just once during its term – at the beginning of the contract when the rates are first established. The shorter the term of the contract, the more frequently prices can be adjusted to ensure they accurately represent the true value of the power. A shorter term contract helps to minimize risk to ratepayers.

Q. Some people have argued over the years that PURPA projects, because the prices are established at the start of the contract term and are fixed for the 20 years of the contract, present little or no fuel-price risk compared to gas-fired generation acquired by utilities. Do you agree?

A. No, I do not. Although there may be no price uncertainty associated with long-term PURPA contracts, that is not the same as having no price risk. Prices established at the start of a long-term contract could prove to be too high or too low compared to other alternatives or to market prices in effect throughout the term of the contract. A long-term contract locks in those prices, regardless of what happens with market prices. Because 100 percent of PURPA costs are passed on to customers through PCAs, ratepayers are fully exposed to the risk that PURPA rates prove to be too high.

Fuel costs associated with utility-owned resources are also passed on to customers, partly through base rates and partly through PCAs. However, fuel costs are tracked annually and rates are adjusted accordingly. Consequently, while customers are exposed to fuel price risk for both PURPA and utility-owned resources, the annual adjustment of rates for utility-owned resources exposes customers to less risk for utility-owned resources than for PURPA resources.

Q. You stated earlier that ratepayers bear 100 percent of the risk when prices in PURPA contracts deviate from actual values of the power over the life of the contract. Why shouldn't ratepayers bear 100 percent of the risk? Don't they bear 100 percent of the risk for utility-owned resources?

A. Ratepayers do bear nearly all of the risk of utility-owned resources, except for relatively small portions that may be borne by the utilities through cost sharing mechanisms built into PCAs. However, because of the annual power cost adjustment mechanisms, the risk for utility-owned resources is less. In other words, the annual adjustment allows costs to be bracketed more accurately.

PURPA resources, on the other hand, receive revenue at fixed rates over long contract terms. I can think of few investments made by private investors in which the rates are fixed and the entire revenue is guaranteed for 20 year periods. Private businesses must almost always make their own assessment of the risks and rewards for new long term investments. I don't think it should be much different when private businesses invest in PURPA projects.

Q. Do you agree that a long-term PURPA contract provides long-term price protection, or a "hedge" against high prices that can benefit ratepayers?

A. It is certainly possible that this could occur, but it is also possible that long-term price certainty could lock in high prices to the detriment of ratepayers. As I stated, price certainty and price protection are not necessarily the same thing.

Q. Do you support Idaho Power's request to limit contract length under the IRP methodology to two years or PacifiCorp's request to limit it to three years?

A. Although I agree with all three utilities' rationale for two or three year maximum contract lengths, I think it could potentially be so short that QFs who did sign contracts would nearly be in perpetual negotiation to renew contracts. For some QFs, the negotiation process can take months or even more than a year. If many QFs signed short two or three year contracts, it could be administratively difficult for both the utilities and the Commission to review, approve, and manage these contracts. Therefore, for practical reasons, I think a five year maximum contract length would be more reasonable. Moreover, the risk associated with 20-year contract is greatly reduced when using a contract of five years.

Q. Do you support Avista's request to limit contract length under the IRP methodology, similar to Idaho Power, but allow Avista the option to sign contracts for more than five years in length if a very favorable opportunity arises? (Reference Kalich, Di at p.3, lines 2-4).

A. For the same reasons just stated for Idaho Power and PacifiCorp, I think a maximum contract length of five years is more reasonable and manageable for all three utilities. With regard to Avista's request to be able to sign contracts for a period of longer than five years in certain circumstances, I believe that option has always existed. I am not opposed to that option continuing to be available for all three utilities, provided that contracts longer than five years can be justified, will benefit ratepayers, and are only used in very rare circumstances.

Q. What contract length have QFs historically chosen, both under the SAR and the IRP methods?

A. The vast majority of QFs in the past have chosen the maximum contract length available at the time, whether they were SAR or IRP contracts. Some QFs have chosen shorter contract lengths, generally less than five years, in most cases because they did not want to be locked into certain rates for long periods of time. In some cases, QFs had some expectation that rates would increase in the future, but wanted to be able to be paid for generation in the meantime until a longer term contract could be signed at more attractive rates.

Q. Do you know what the maximum contract length is for PURPA contracts in other states?

A. I am not familiar with all other states in the U.S. in which there is significant PURPA activity, but I do know that maximum contract length is currently 20 years in Oregon, Utah, and Wyoming. It is 25 years in Montana, but only five years in Washington. In areas where non-utility generators have ready access to wholesale power markets such as PJM, ISO New England, New York ISO, California ISO, Southwest Power Pool and ERCOT, there is no mandatory purchase obligation under PURPA, thus, no maximum contract length.

Q. Do you believe there may be other options besides reducing contract lengths that could also address the problem?

A. The Commission, in Order No. 32697 suggested that it believed other tools, besides shortened contract lengths, could be utilized to ensure an accurate and up to date avoided cost valuation. However, the Commission stopped short of suggesting what those tools should be. Trying to determine accurate avoided cost rates from the beginning of the contract is, obviously, a first step. Although I believe avoided costs are reasonably being computed today under the IRP method, I also believe that there may be additional factors that are currently not being considered. For example, solar projects are currently eligible for tax credits valued at up to 30 percent of the project cost. Presumably, the value of these credits is being realized by the owners or financiers of the projects, but is not being passed on to the utility or its ratepayers. If a utility acquired a comparable solar project or its output through a competitive solicitation, I would assume the value of any tax incentives would be reflected in the purchase price and therefore passed on indirectly to ratepayers. Currently, tax incentives are not accounted for in the IRP methodology, yet they provide tremendous benefit to QFs.

There could be other potential changes to the way in which avoided cost rates are calculated, but none would adequately address the real problem—rates becoming inaccurate over long contract lengths.

Q. Do you believe a periodic rate adjustment mechanism could work, while maintaining QFs' option to choose 20-year contracts?

A. In theory, periodically adjusting rates throughout the term of the contract, say at two to five year intervals, could help to ensure that avoided cost rates in the contract remain accurate and reflect the proper value compared to the market or other alternatives. Similarly, indexing prices in the contract based on electric market indexes or fuel prices could accomplish the same thing.

Q. Do you believe QFs would find periodic rate adjustments acceptable?

A. No, I do not. I expect QFs would view adjustable rates, either through reopeners or indexing, to be nearly comparable to short term contracts. Because prices are the single most important element in a contract, periodic adjustment of those prices could be functionally equivalent to signing a new contract to QF owners and financiers.

Q. Do PURPA or FERC rules allow periodic rate adjustments?

A. FERC and various courts have made clear that avoided cost rates contained in a PURPA contract cannot be modified after the contract has been signed, although neither the Idaho nor the U.S. Supreme Courts have held as much. However, FERC rules do not specifically address whether adjustable rate contracts are acceptable in instances in which the contracting parties agree in advance to an adjustment method and frequency. Consequently, I am uncertain as to whether FERC would find adjustment mechanisms acceptable. Because of this uncertainty, and because I believe QFs would view periodic rate adjustments as functionally equivalent to new contracts, I think shorter contracts are the best approach to reduce the financial or price risk of long-term contracts.

Q. Do you agree that PURPA projects will always be paid too much under 20-year contracts?

A. No, not necessarily. While it is true that avoided cost rates have exceeded comparable market prices throughout most of the history of PURPA in Idaho, there have been times when this was not true. For example, during the extreme electricity price spikes in late 2001-2002, market price far exceeded avoided cost rates for extended periods of time.

Price comparisons at any single snapshot in time are generally not valid projections over a long period of time. Contractual avoided cost rates will nearly always be higher or lower than comparable market prices over the long-term such as 20 years. What is important is that the prices are close over the entire course of the contract term.

Now that a few contracts have reached or are nearing their 20 or 35-year expiration, a comparison can perhaps be made. However, in my opinion, if avoided cost rates in any contracts have proven to be accurate over time, it has been just by chance, not by design.

Q. Do you think it is fair for utilities to be permitted to develop or acquire long-term generation assets, but to only be obligated in the case of PURPA resources to two, three, or five year contracts?

A. Whenever a utility acquires a resource or signs a long-term PPA for new generation, it must identify the need in its IRP, evaluate a range of alternatives, and procure the resource or contract through a competitive process. Throughout the entire process, the utility's decisions are subject to intense scrutiny by the Commission, intervenors, and other interested parties, including customers. If the utility cannot first demonstrate a need and second justify the cost-effective resource, it does not receive Commission approval to pursue the project.

As examples of utility acquisitions of non-PURPA renewable projects, Idaho Power's Neal Hot Springs and Raft River geothermal PPAs and its Elkhorn Wind PPA were signed as a result of geothermal and wind resources being identified as preferred resources in the utility's IRP. Similarly, Avista's Palouse Wind Project PPA and several PacifiCorp wind projects and PPAs were identified through the IRP process and acquired through subsequent competitive procurement processes.

Q. Was the procurement of thermal projects by utilities, such as Idaho Power's Langley Gulch project, PacifiCorp's Lakeside II, or Avista's Lancaster PPA any different than the acquisition process employed for renewables? Aren't those examples of long-term commitments that bind ratepayers for very long periods of time?

A. Just like the renewable projects previously discussed, the utilities' thermal facilities mentioned above also had to pass intense scrutiny before the utilities were permitted to procure them. While it is true that utilities are permitted to sign long-term contracts and secure long-term financing, for most projects there is no guaranteed complete cost recovery at fixed rates. For example, in the case of Idaho Power's Langley Gulch project, various costs of the facility are included in base rates for recovery over the life of the plant. However, fuel costs, which can represent as much as two thirds of the total cost over the facility's lifetime, are subject to annual adjustment to the extent actual costs vary from what is included in base rates. Moreover, most of these thermal generating facilities provide other benefits such as dispatchability, variable ramp rates, reserves and other ancillary services.

PURPA projects, on the other hand, are treated differently. They are currently entitled to long-term contracts at fixed rates. The utility is obligated to sign contracts at Commission-approved rates, with no consideration of need, with no competitive procurement process, and without regard to cost-based pricing. Recovery of PURPA contract payments by the utility is through a combination of base rates and PCAs, but always at 100 percent. There is no adjustment to the avoided cost rates or to the amount authorized for recovery from ratepayers throughout the entire term of the contract.

Q. Can PURPA cogeneration projects like Simplot or Clearwater present additional risks over non-cogeneration PURPA projects?

A. Perhaps. Cogeneration projects are always associated with some other industrial process besides generating electricity. Consequently, they face business risks independent of their electric production. If the thermal host for a cogeneration facility goes out of business, then the electric production cannot continue. Some examples of this have been the Magic West facility in Glenns Ferry and the Yellowstone Power project at Emmett.

Q. Do you believe PURPA is an effective mechanism for utilities to acquire new generation?

A. No, I do not. I believe PURPA was intended to permit relatively small, non-utility-owned projects to be developed and to compete on an equal footing with utility-owned facilities. I do not believe PURPA was ever intended to serve as the primary, or even a major, mechanism for utility acquisition of new resources. Instead, at least for Idaho Power and perhaps PacifiCorp, PURPA resources have become major resources, forced upon them with no planning whatsoever. PURPA projects entirely circumvent the planning process and sometimes cause the utility to plan around them rather than planning for them.

This creates a very awkward and inefficient planning process and can lead to a poorly conceived generation fleet that is not in the best interests of ratepayers. Therefore, I do not support long-term contracts to encourage PURPA at a time when utilities would not otherwise be making long-term commitments for non-PURPA generation resources.

Q. Each of the utilities' petitions in this case have asked to reduce the maximum length of only IRP-based contracts; however, SAR-based contracts continue to be eligible for 20-year contracts. Do you believe 20-year maximum contract lengths should continue to be available to SAR-based contracts?

A. Yes, I do. Twenty year contracts should continue to be available for wind and solar projects smaller than 100 kW, and for all other project types smaller than 10 aMW.

Q. If maximum contract lengths are reduced to less than 20 years in this case for IRP-based contracts, are you concerned about the difference in contract length between SAR-based and IRP-based contracts?

A. No, I am not. Although there would be a difference between maximum contract length for IRP and SAR-based contracts, I believe such a difference is reasonable. In the past, there have been instances in which contract rates and/or terms were much more favorable for SAR-based than for IRP-based contracts, and it has led to QF developers strongly preferring one contract type over the other. One recent example was the disparity in rates (either real or perceived) between IRP and SAR rates, which led to disaggregation of large wind farms into smaller 10 MW projects.

In this case, most new PURPA projects are likely to be solar, and the size limit or eligibility cap for SAR-based solar contracts is 100 kW. Because this cap is 100 kW, I believe it is unlikely a QF would be disaggregated into such small pieces in order to qualify for SAR-based rates, or more importantly, for 20-year contracts. The same would likely be true for wind projects.

In addition, SAR-based projects do not represent a significant portion of the cumulative amount of PURPA generation. For example, wind and solar projects (both under contract and proposed) account for more than 1973 MW of Idaho Power's PURPA projects according to Idaho Power Exhibit No. 1. Thus, the impact of SAR-based projects is very small in comparison to the magnitude of IRP-based projects.

Q. Does your proposal to maintain 20-year contracts for new SAR-based projects also apply to SAR-based contracts that will be expiring and that desire new contracts?

A. Yes, it does.

Q. Please discuss the number and timing of expiring SAR-based contracts.

A. In the coming years, many existing PURPA contracts will expire and will be seeking replacement contracts. Exhibit No. 101 depicts graphically the timing and number (but not the amount of generation) of QF contracts that will be expiring. Each line on the graph represents a different contract. In the coming 10 years, 94 contracts will expire and could choose to be renewed.

Q. Why should SAR-based contracts be permitted longer contracts than IRP-based contracts?

A. Neither SAR-based nor IRP-based rates are likely to remain accurate over a 20-year period. On a per kW basis, the risk for SAR-based contracts is exactly the same as for IRP based contracts. However, SAR-based contracts, because the project sizes are individually and collectively small, present much less risk if contract rates prove to be too high or too low compared to the actual value of the power.

Q. Should SAR-based replacement contracts be permitted 20-year terms?

A. Yes, I recommend that all SAR-based contracts be eligible for 20-year contracts, regardless of whether they are for new projects or for replacement contracts. SAR-based projects that are renewing contracts will receive the then current energy rates and capacity rates. Even though projects seeking replacement contracts presumably have already been financed and retired their debt, for consistency sake I think it is reasonable that all SAR-based contracts follow the same rules.

Contracts that were initially SAR-based, but at the time of contract replacement exceed the size threshold for SAR-based rates, should be treated as new IRP-based contracts but eligible for capacity payments throughout the entire contract term.

Q. Please summarize your recommendations.

A. I recommend that the maximum contract length for standard IRP-based contracts be five years for Idaho Power, PacifiCorp, and Avista. I also recommend that the maximum contract length for SAR-based contracts remain at 20 years, both for new and for replacement contracts.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

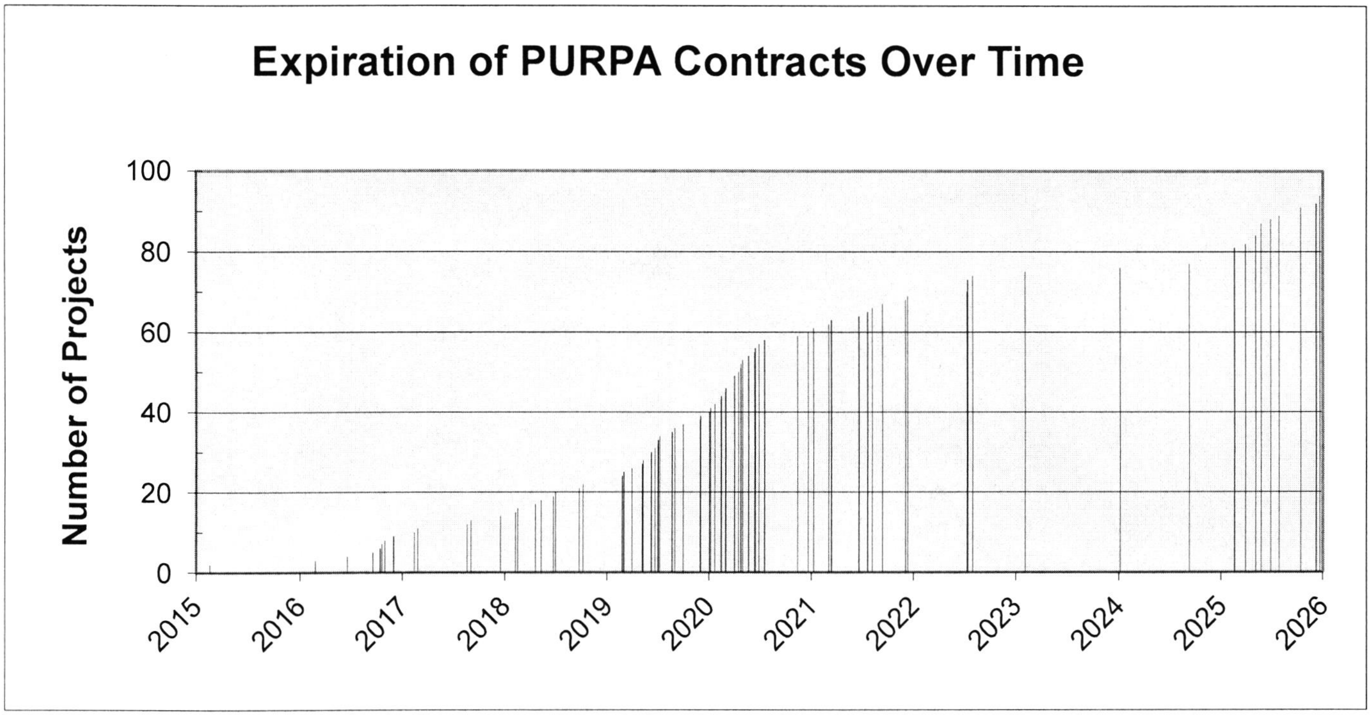

Exhibit No. 101
Case No. IPC-E-15-01
AVU-E-15-01
PAC-E-15-03
R. Sterling, Staff
4/23/15

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 23RD DAY OF APRIL 2015, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NOS. IPC-E-15-01/PAC-E-15-03/AVU-E-15-01, BY E-MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

DONOVAN E WALKER
REGULATORY DOCKETS
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-mail: dwalker@idahopower.com
dockets@idahopower.com

PETER J RICHARDSON
GREGORY M ADAMS
RICHARDSON ADAMS PLLC
PO BOX 7218
BOISE ID 83702
E-mail: peter@richardsonadams.com
greg@richardsonadams.com

DR DON READING
6070 HILL ROAD
BOISE ID 83703
E-mail: dreading@mindspring.com

BENJAMIN J OTTO
ID CONSERVATION LEAGUE
710 N 6TH STREET
BOISE ID 83702
E-mail: botto@idahoconservation.org

DEAN J MILLER
McDEVITT & MILLER LLP
420 W BANNOCK ST
BOISE ID 83702
E-mail: joe@mcdevitt-miller.com

LEIF ELGETHUN
INTERMOUNTAIN ENERGY PARTNERS LLC
PO BOX 7354
BOISE ID 83707
E-mail: leif@sitebasedenergy.com

KELSEY JAE NUNEZ
SNAKE RIVER ALLIANCE
PO BOX 1731
BOISE ID 83701
E-mail: knunez@snakeriveralliance.org

KEN MILLER
SNAKE RIVER ALLIANCE
E-MAIL ONLY:
kmiller@snakeriveralliance.org

TED WESTON
ID REG AFFAIRS MANAGER
ROCKY MOUNTAIN POWER
201 S MAIN ST STE 2300
SALT LAKE CITY UT 84111
E-mail: ted.weston@pacificorp.com

DANIEL E SOLANDER
YVONNE R HOGLE
ROCKY MOUNTAIN POWER
201 S MAIN ST STE 2400
SALT LAKE CITY UT 84111
E-mail: daniel.solander@pacificorp.com
yvonne.hogle@pacificorp.com

DATA REQUEST RESPONSE CENTER
E-MAIL ONLY:
datarequest@pacificorp.com

C TOM ARKOOSH
ARKOOSH LAW OFFICES
PO BOX 2900
BOISE ID 83701
E-mail: tom.arkoosh@arkoosh.com

ERIN CECIL
ARKOOSH LAW OFFICES
E-MAIL ONLY
erin.cecil@arkoosh.com

ERIC L OLSEN
RACINE OLSON NYE BUDGE
& BAILEY
PO BOX 1391
POCATELLO ID 83204-1391
E-mail: elo@racinelaw.net

ANTHONY YANKEL
29814 LAKE ROAD
BAY VILLAGE OH 44104
E-mail: tony@yankel.net

RONALD L WILLIAMS
WILLIAMS BRADBURY PC
1015 W HAYS ST
BOISE ID 83702
E-mail: ron@williamsbradbury.com

IRION SANGER
SANGER LAW PC
1117 SW 53RD AVE
PORTLAND OR 97215
E-mail: irion@sanger-law.com

MICHAEL G ANDREA
AVISTA CORPORATION
1411 E MISSION AVE
MSC-23
SPOKANE WA 99202
E-mail: michael.andrea@avistacorp.com

CLINT KALICH
AVISTA CORPORATION
1411 E MISSION AVE
MSC-23
SPOKANE WA 99202
E-mail: clint.kalich@avistacorp.com

MATT VESPA
SIERRA CLUB
85 SECOND ST 2ND FLOOR
SAN FRANCISCO CA 94105
E-mail: matt.vespa@sierraclub.org

RICHARD MALMGREN
SR ASSIST GEN COUNSEL
MICRON TECHNOLOGY INC
800 S FEDERAL WAY
BOISE ID 83716
E-mail: remalmgren@micron.com

FREDERICK J SCHMIDT
PAMELA S HOWLAND
HOLLAND & HART LLP
377 S NEVADA ST
CARSON CITY NV 89703
E-mail: fschmidt@hollandhart.com

SCOTT DALE BLICKENSTAFF
AMALGAMATED SUGAR CO
1951 S SATURN WAY
STE 100
BOISE ID 83702
E-mail: sblickenstaff@amalsugar.com

ANDREW JACKURA
SR VP NORTH AMERICA DEVL
CAMCO CLEAN ENERGY
9360 STATION ST STE 375
LONE TREE CO 80124
E-mail: andrew.jackura@camcocleanenergy.com

CAROL HAUGEN
CLEARWATER PAPER CORPORATION
E-MAIL ONLY
Carol.haugen@clearwaterpaper.com

Jo Nelson
SECRETARY