BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1725

In the Matter of	)
	)
IDAHO POWER COMPANY,	)
	)
Application to Lower Standard Contract Eligibility Cap and to Reduce the Standard Contract Term, for Approval of Solar Integration Charge, and for Change in Resource Sufficiency Determination.	))))))

RESPONSE TESTIMONY OF

JOHN R. LOWE

ON BEHALF OF THE

RENEWABLE ENERGY COALITION

July 31, 2015

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John R. Lowe. I am the director of the Renewable Energy Coalition (the "Coalition"). My business address is 12040 SW Tremont Street, Portland, Oregon 97225.

Q. Please describe your background and experience.

A. In 1975, I graduated from Oregon State with a B.S. I was employed by PacifiCorp for thirty-one years, most of which was spent implementing the Public Utility Regulatory Policies Act ("PURPA") regulations throughout the utility's multi-state service territory. My responsibilities included all contractual matters and supervision of others related to both power purchases and interconnections. Since 2009, I have been directing and managing the activities of the Coalition as well as providing consulting services to individual members related to both power purchases and interconnections.

Q. On behalf of you are you appearing in this proceeding?

A. I am testifying on behalf of the Coalition.

Q. Please describe the Coalition and its members.

A. The Coalition was established in 2009, and is comprised of thirty members who own and operate nearly fifty non-intermittent small renewable energy generation qualifying facilities ("QFs") in Oregon, Idaho, Montana, Washington, Utah, and Wyoming. Several types of entities are members of the Coalition, including irrigation districts, water districts, corporations, and individuals. Except two, all are small hydroelectric projects.

Q. What are the Coalition's interests in this proceeding?

A. The Coalition has a number of key interests in this proceeding. First, our goal is to ensure fair and reasonable contract terms and conditions, and avoided cost rates for small projects under the standard contract and rate eligibility cap. Second, the Coalition's members are primarily existing QFs, and our goal is to ensure that any final order in this proceeding recognizes and accounts for the unique circumstances and benefits of existing projects. Finally, the Coalition recognizes that PURPA must work to benefit all interested parties, including the utilities, ratepayers, and new and existing QFs of various sizes. The Coalition's goal is that PURPA policies account for all these interests, and the changes (if any) adopted by Oregon Public Utility Commission (the "Commission") are narrowly tailored to resolve specific problems. Any policy changes should not unduly harm any one, especially parties not causing the problems that led to the utilities' filings.

Q. Please summarize Idaho Power's requests in this case.

A. Idaho Power has requested: 1) to lower the standard contract eligibility cap to 100 kW for wind and solar QFs; 2) to lower the standard contract term to two years for wind and solar QFs; 3) approval of a solar integration charge; and 4) to change its resource sufficiency determination.

Q. Please summarize your testimony.

A. The alleged problems facing Idaho Power are exaggerated, and the problems (if any) are not caused by baseload QFs, and any policy changes (if any) that result from these proceedings should exempt baseload projects. Second, I explain the unique reasons why that there should be no change in policy for existing projects. Existing projects are also not causing any problems, and in fact are providing significant benefits to the utilities. In addition, imposing a policy change like a shortened contract term on existing QFs could have significant and unnecessary harm on these projects, the utilities, and ratepayers.

Q. What are your specific responses to Idaho Power's filings?

A. First, the Commission should not lower the size threshold or contract terms for any QFs. However, if the Commission lowers the size threshold or contract terms, then it should not apply to baseload QFs, which is consistent with Idaho Power's recommendation in this case. Second, the Commission should not change Idaho Power's resource sufficiency period or capacity deficit at this time. Third, the Coalition has no position on Idaho Power's solar integration charge at this time.

II. CONTRACT TERM AND SIZE THRESHOLDS SHOULD NOT BE REDUCED

Q. Please describe the alleged problems facing the Idaho Power.

A. Idaho Power has supported its request to reduce the contract term with claims regarding the harm caused by new large wind and solar QFs. For example, Idaho Power states that they have a large amount of new wind and solar projects under contract, and a large number of additional wind and solar QFs seeking new contracts. Idaho Power alleges significant customer rate and reliability concerns associated with this large amount of large wind and solar QFs.

Q. Do you agree with Idaho Power that they are facing significant problems associated with new PURPA projects?

A. I agree that Idaho Power is facing a large number of new contract requests and new contracts. This is a legitimate issue that warrants consideration.

In my experience, not all of the QFs that request contracts, or that even enter into contracts, ever come on line. I worked at PacifiCorp after PURPA was passed and in the early years there was a huge number of new requests for hydroelectric projects, and only a small fraction were developed. Over my years at PacifiCorp, very few of the projects that sought contracts, or even of those that signed contracts, eventually became operating and selling electricity.

Utilities like Idaho Power also typically over estimate the costs and harms associated with QFs, and underestimate their benefits. Utilities do not earn a return on purchases from QFs, and often allege that they harm ratepayers even when QFs are a lower cost and more reliable source of power than the market or the utilities' own generation resources.

In any event, these problems are not caused by baseload projects under the current standard contract rate threshold. I will address this later in my testimony.

Q. Do you have any indication that Idaho Power's potential problems may be exaggerated?

A. Yes. Idaho Power has a history of exaggerating the level of expected new QFs. In 2012, Idaho Power claimed it was facing a "deluge" of over 70 MWs of new Oregon wind QFs. This deluge quickly dried up with Idaho Power entering into far fewer contracts. I am not aware of any of these operating.

Idaho Power now states that it entered into 461 MWs of new solar generation in Oregon and Idaho. Application to lower standard contract eligibility cap and to reduce the standard contract term ("Application") at 1-2. Idaho Power, however, admits that almost a third or 144 MWs have already had their contracts terminated. Idaho Power also alleges that it currently has an extraordinary level of requests for new PURPA contracts, including "additional 1,326 MW of solar capacity actively seeking PURPA contracts, 245 MW of which are in Oregon." Application at 2.

Despite these potential contracts, there are a number of reasons why this new solar generation may not occur. For example, it appears that Idaho Power no longer has much available transmission capacity, and any new QFs will be required to pay for expensive transmission upgrades. Specifically, Idaho Power states:

> The five Oregon Qualifying Facility ("QF") wind projects and the six Oregon QF solar projects will require network transmission upgrades for network transmission service. These projects will use all of the incremental transmission capacity from their respective network transmission upgrades leaving no transmission capacity for additional generation projects, regardless of size, in this area of Idaho Power's transmission system.

It is extremely unlikely that Idaho Power will have sufficient available interconnection and transmission capacity to accommodate a large amount of any type of new generation, especially given the current the historically low avoided cost rates. Transmission issues alone could put a sudden halt to much of the potential QF development. In addition to transmission issues, there are the traditional forces related to project financing, ordinary risks of development, interconnection costs, utility hostility, and many other factors that will reduce the number of projects that are eventually constructed.

Q. How should the Commission address the alleged problems facing Idaho Power?

A. The Commission should reject Idaho Power's proposal to lower the size threshold and standard contract term for wind and solar QFs. Alternatively, if the Commission is inclined to adopt any relief, then it should not apply to small or existing baseload QFs. This alternative recommendation is consistent with Idaho Power's recommendation that relief be limited to wind and solar QFs.

Q. Please describe what you mean by projects under the standard contract rate threshold.

A. The standard contract rate eligibility threshold is the maximum size for a QF to be eligible to sell power at a utility's published avoided cost rates. The current rate eligibility cap is 10 megawatts ("MW") for all generation resources, except there is a temporary 3 MW cap for solar generation.

Q. Is the standard contract and rate threshold important?

A. Yes. It is much more difficult for QFs to negotiate contracts over the rate eligibility cap than those below the cap. All states that I work in allow smaller QFs to obtain published rates instead of negotiating rates or having their rates determined by a utility computer model.

Q. Why are small projects treated differently than larger projects?

A. There are a number of important reasons for treating smaller projects differently, some which include developer sophistication, transaction costs, economies of scale, and the inability to economically access alternative markets. It is important to recognize the unique difficulties facing smaller projects, and allowing smaller projects to sell power at a published rate helps mitigate some of these difficulties.

Negotiating contracts can be costly in terms of upfront transactional costs. Small QFs do not typically have in house attorneys and experts with the skills to assist in the evaluation and negotiation of contracts. Therefore, they often need to hire outside experts. In addition, negotiating a QF contract with a utility can take a great deal of time. All of these transactional costs can impose significant economic burdens, and even make a smaller project uneconomical.

Most small projects also do not have the options available to larger projects. This is especially true for small hydro, geothermal and many biomass projects. For example, large scale resources developed by utilities or large independent power producers benefit from being sized so that the dollar-per-kilowatt investment required to build the plant is less than for a much smaller sized QF of the same basic technology. Similarly, it is my understanding that the typical short-term power sale trades in the Pacific Northwest electricity market are for blocks of 25 MW power, and small QFs cannot effectively participate in this market.

Q. Please explain what you mean by existing QFs?

A. Existing QFs are those projects that are already operating and are generally selling power to the interconnected utility. Some of these projects have been operating since the mid 1980s.

Existing projects face some unique challenges. Existing projects must enter into a replacement power purchase agreement ("PPA") when their current

PPA expires. In Oregon, this always means that their new PPA starts during a term that includes an initial period of utility resource sufficiency. Most existing projects have been operating for years, and may require major replacement and/or upgrading of their equipment, conveyance structures and other facilities including interconnections. New interconnection agreements are often required. There can be significant costs involved in addressing these needs or requirements

Q. Are existing QFs treated differently than new QFs?

A. Yes. For example, existing QFs are included in the utilities' resource plans. These QFs have been and will continue to contribute to the utilities' capacity needs, which justifies paying existing QFs a capacity payment that recognizes their capacity value when they renew their contracts regardless of the utilities' resource position. California and Idaho require capacity payments to existing QFs during the resource sufficiency period to recognize that they provide capacity value to the utilities during all years and are expected to continue to sell power to the utilities.

Q. Would changing PURPA policy to include a two-year or another short contract term harm these existing and small projects?

A. Yes. Currently, small QFs can enter into a twenty-year contract term (the last five years are based on market prices).

Renegotiating PPAs can be time consuming and costly, especially for small and existing QFs, and could be expected to be very burdensome if required every five years or less. As I explained above, small existing facilities nearly always do not have the option of selling their power to other entities, and typically only have the choice of continuing to sell their power to their interconnected utility or shutting down. Also, since existing QFs, especially small hydro projects that are FERC licensed or exempted are not going mobile, there is no need to place a significant burden and the cost of constantly entering into new short-term contracts.

Significantly shortening the contract term for small QFs would also harm the utilities and ratepayers. It is my understanding that that small hydroelectric QFs below the rate eligibility cap make up the majority of Idaho Power's overall system individual PURPA projects. According to Idaho Power, small hydroelectric projects make up 68 of the total 133 that utility's PURPA projects under contract. Requiring the utilities to renegotiate all of these small QF contracts every two years, for example, would be costly for the utilities. These unnecessary costs would be passed on to ratepayers.

Q. Would the practical result of Idaho Power's short contract terms result in QFs never or almost never being paid for capacity?

A. Yes. Idaho Power's proposal for short contract terms means that there will always be a period of resource sufficiency, which may prevent QFs from being paid for capacity. If the resource sufficiency period is short and the contract term length is limited to a couple or few years, then projects will no longer receive capacity payments because the next capacity deficit will normally be more than the contract term.

Q. Can you provide an example?

A. Yes. Under Idaho Power's proposal, QFs will not be paid for capacity if they enter into a contract when the next thermal resource acquisition is in longer than the contract term. For example, assume that Idaho Power is planning its next thermal resource acquisition in three years (2018). Under Idaho Power's proposal, a QF that enters into a new two-year contract in 2015 will not be paid for capacity during the entire contract term. In 2018, Idaho Power will have a new IRP, which will likely not be planning on a new thermal resource for more than two years, and its new avoided costs will not have any capacity payments during this "sufficiency" period. If the QF renews its contract and enters into a new two-year contract in 2018, then the QF will again not be paid for capacity. The QF could continue entering into renewing contracts for the rest of its useful life, but never be paid for capacity. The QF will have caused Idaho Power to reduce both its energy and capacity needs (including the capacity related to the next planned thermal resource), however, the QF will not be paid for capacity under the company's approach.

This example highlights the ridiculousness of Idaho Power's proposed two year contract term. If contract terms are shortened to five or ten years, then similar problems will exist. As long as the contract term is shorter than the resource sufficiency period, then the QFs will not be paid for capacity.

Q. Are small and existing projects contributing to the utilities' alleged problems?

A. No. Assuming that all of the utilities alleged problems are true, these problems are not being caused by existing and small QFs. Idaho Power should be commended for recognizing this fact when it requested that its relief only apply to wind and solar. It is appropriate for any utility when seeking a change in policy to narrow its requested relief in a manner that solves the particular problem and does not cause unintended consequences. Idaho Power took the first step in only directing its relief toward those QFs that are arguably causing problems. While I disagree that the potential problems alleged by Idaho Power warrant any relief, I appreciate that Idaho Power at least recognized that small and existing baseload QFs benefit rather than harm ratepayers.

For example, the hydroelectric projects under the rate eligibility cap provide only 154 megawatts of the total current 1,302 megawatts of PURPA nameplate generation. While there is a large number of QFs under the published rate eligibility cap, the total megawatt size of these existing projects is small and not causing the alleged rate or reliability concerns identified by Idaho Power.

In fact, these projects provide Idaho Power with significant benefits. For example, many of these projects are seasonal, which means that they provide Idaho Power with valuable capacity. Limiting the contract length to these projects not only does not address the problems identified by Idaho Power, but may harm both Idaho Power and its ratepayers. The Commission's final order in this proceeding should be careful not to harm those QFs that are not contributing to the problems faced by the utilities.

II. CHANGE IN RESOURCE SUFFICIENCY AND DEFICIENCY PERIOD

Q. What is Idaho Power proposing regarding its resource sufficiency and deficiency period?

A. Idaho Power has requested a change in the demarcation between its resource sufficiency and deficiency period from 2016 to 2021.

Q. Why is this important?

A. The demarcation between resource sufficiency and deficiency also called the date of the next capacity deficit. This is something of a misnomer because the utilities often acquire capacity resources during their sufficiency period and the estimated resource sufficiency period is often overstated. Also, the integrated resource plan has little analysis regarding the correct demarcation regarding resource sufficiency and deficiency because the demarcation is typically outside of the Action Plan.

For avoided cost rate purposes, however, this demarcation is very important because during the period of resource sufficiency avoided cost prices are based on market purchases, and during the period of resource deficiency avoided cost prices are based on the costs of a thermal resource (or a renewable resource for the renewable avoided cost rates of PacifiCorp and Portland General Electric, but not Idaho Power). Thus, there is a relatively arbitrary and inaccurate date for a capacity deficit that has a huge impact on avoided cost rates.

Q. What is your recommendation?

A. The Commission should reject Idaho Power's request. Idaho Power's request is an out of cycle avoided cost update, and such updates previously have been disfavored by the Commission. The Commission has established policies for changing avoided cost rates, and Idaho Power's request to change to extend its resource sufficiency period without a acknowledged IRP update or acknowledgment of the new 2015 IRP is inconsistent with these policies.

Also, Idaho Power's request is unnecessary. Idaho Power has already filed its 2015 integrated resource plan, which may be acknowledged by the Commission shortly after this proceeding is completed. All of the discussion regarding capacity deficits and resource sufficiency periods in this proceeding may be an unnecessary waste of valuable utility, Commission, and QF resources. The utility's and Commission's costs are ultimately paid for by ratepayers.

Q. What is the Commission's established process for avoided cost rate changes?

A. The Commission has approved a process for changing avoided cost rates annually at a specific time (May 1) plus another potential update after IRP acknowledgement. The Coalition generally supports this process because it allows frequent avoided cost updates, but a more predictable avoided cost rate update schedule than under the Commission's previous ad hoc updates.

Recounting the history of why we have the current process may be helpful to understand why Idaho Power's proposed update should be rejected. By statute, avoided cost rate updates should occur every two years, and must happen in a manner that allows for a settled and uniform institutional climate for QFs. The Commission historically has allowed the utilities to update their avoided cost rates at least every two years coincident with the IRP process.

While the Commission had a two-year update policy, in practice parties have requested and sometimes obtained avoided cost rate updates more frequently than every two years. In other words, the Commission's standard two-year cycle was not consistently followed, which resulted in ad hoc updates that resulted in significant pricing uncertainty to QFs negotiating contracts with the utilities. This harmed QFs because predictability of price changes is one of the most important aspects of project development and continued operation, and unforeseen avoided cost updates can prevent a QF from successfully completing a contract. Unscheduled updates would completely upset a QF's plans to complete their negotiation process before a scheduled update will occur to obtain price certainty and not have their avoided cost rates significantly change in the middle of the negotiation process. QFs and the utilities have an asymmetrical level of information, including whether an update will increase or decrease the avoided cost rates.

Overall, unexpected updates have been an additional barrier to QF development and the utilities have used them as an opportunity to delay the negotiation process. The utilities have an incentive to delay the negotiation process or impose other barriers to finalizing a contract if avoided cost rates are declining, and the opposite incentive if avoided cost rates are increasing. This is exemplified by Idaho Power's actions in this case in which it delayed contract negotiations based on its knowledge that it planned to file its applications to lower avoided cost rates, size thresholds, and contract lengths.

In order to reduce these problems, the Commission adopted its current process of annual updates and an update after IRP acknowledgment (with the opportunity to waive one of the updates if they occur with in 60 days of each other). Docket No. UM 1610, Order No. 14-058 at 25-26. This protects ratepayers from outdated avoided cost rates, but also provides QFs with predictability and certainty regarding rate changes.

Q. Is Idaho Power's request to change the sufficiency period consistent with the Commission's policy on avoided cost updates?

A. No. Idaho Power's request to change its resource sufficiency period is what the Commission calls an "out of cycle update." The Commission also established guidelines regarding whether out of cycle updates should be allowed, stating that it would make it more difficult for parties to obtain updates outside of the normal process than in the past:

> we will continue to allow requests for mid-cycle updates for significant changes to avoided cost prices. However, in light of our decision here to require annual updates in addition to updates following IRP acknowledgement, we caution stakeholders that the "significant change" required to warrant an out-of-cycle update will be very high.
> We expect the parties to use this option infrequently.

Docket No. UM 1610, Order No. 14-058 at 25-26.

Q. Do you believe Idaho Power has met this "very high" standard?

A. No. I do not believe that Idaho Power has provided clear and convincing evidence to meet this "very high" standard for an early adjustment in its avoided cost rates. Idaho Power states that the early update is warranted because the inclusion of 440 MW of demand response would shift the capacity deficit to 2021 from 2016. I agree that both the size of the resource acquisition and the change from 2016 to 2021 by themselves could potentially be considered significant.

My concern primarily has to do with timing, and reviewing this change in isolation. Idaho Power filed an integrated resource plan on June 30, 2015. The IRP is supposed to be processed in a little over six months. OAR § 860-027-0400(10)(b).[1] I understand that IRPs have become more complex and can last over six months, but Idaho Power should have an acknowledged IRP early in 2016. This may be only a month or two after a final order in this proceeding. The Commission should not accept or approve a filing that is designed to result in a

[1] The rule reads: "Commission staff and parties must file any comments and recommendations with the Commission and present such comments and recommendations to the Commission at a public meeting within six months of the energy utility's filing of its request for acknowledgement of proposed change."

major avoided cost rate change only a month or two before the utility's IRP is acknowledged (which results in a new avoided cost rate change based on more complete information).

Q. Is there Commission precedent for rejecting Idaho Power's proposal?

A. Yes. Before the Commission established its current "very high" standard, it rejected a request by QFs to increase avoided cost rates after a dramatic increase in gas prices under a lower standard. At the time Idaho Power opposed the change because it was planning to file new avoided cost rates soon and the gas price change was only one factor among many that should be taken into account. This is similar to the current circumstances with Idaho Power planning to file updated avoided cost rates soon after the completion of this proceeding based on more than one factor.

In 2007, the Commission recognized that the facts of the situation would result in a major change in avoided cost rates and that "may warrant the updated avoided cost filings as contemplated by" its previous orders. Order No. 07-199 at 2. In other words, the Commission agreed that the avoided cost rates were going to updated soon and were inaccurate. Despite this, the Commission rejected the attempt to revise avoided cost rates early because the utilities would need to file new avoided cost rates soon.

The same rationale applies here. When Idaho Power made its filing, an annual avoided cost update was expected in only one week. Similarly, Idaho Power's avoided cost rates will need to be revised shortly after the completion of a final order in this proceeding to account for changes in the company's integrated resource plan. As Idaho Power explained in 2007, the IRP will account for a myriad of potential issues and more than just the additional demand response resources. The Commission should reaffirm that it will use the process of annual updates, and an update after IRP acknowledgement, and reject Idaho Power's proposed change in its resource sufficiency.

III. CONCLUSION

Q. Please summarize your testimony.

A. The Commission should reject Idaho Power's proposal to lower the size threshold and contract term for wind and solar QFs. In the alternative, if the Commission lowers the contract term to anything short of twenty years or size threshold to anything less than 10 MWs, whatever relief adopted should only apply to wind and solar QFs, as Idaho Power has requested. The Commission should not update Idaho Power's resource sufficiency period or capacity deficit in a stand alone proceeding because it would upset the expectations of QFs and it is unnecessary. Most importantly, allowing an avoided cost rate change in this proceeding would create a dangerous precedent and harmful uncertainty regarding when utility's can update their avoided cost rates. All of this would occur when it will have little practical impact.

Q. Does this conclude your testimony?

A. Yes