BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF WYOMING

IN THE MATTER OF THE APPLICATION	**)**	
OF ROCKY MOUNTAIN POWER FOR	**)**	**DOCKET NO. 20000-518-EA-17**
APPROVAL OF SCHEDULE 37 STANDARD	**)**	**(Record No. 14736)**
RATES FOR PURCHASES OF POWER	**)**	
FROM QUALIFYING FACILITIES	**)**	

TESTIMONY AND ATTACHMENTS OF

JOHN R. LOWE

November 6, 2017

SUBMITTED ON BEHALF OF
RENEWABLE ENERGY CORPORATION

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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 P.O. Box 25576 Portland, Oregon 97298.

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 whom 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 over 30 members who own and operate over 50 mostly 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, waste management districts, water districts, electric cooperatives, corporations, and individuals. Most are small hydroelectric projects, but the membership includes biomass, geothermal, solid waste, and solar projects. Shoshone Irrigation District, which owns and operates the Garland Canal project, is the Coalition's sole operating Wyoming member. The fact that the Coalition only has one irrigation district member in Wyoming is indicative of the concerns expressed in this testimony. Other Coalition members would like to develop local community based renewable projects in Wyoming.

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

A. The Coalition has a number of key interests in this proceeding. Our goal is to ensure fair and reasonable avoided cost rates for QF projects. In doing so, it is especially important to recognize both the undervaluation of energy and capacity under the current avoided cost filing. The Coalition's members are primarily small and 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 small and existing renewable projects. However, as mentioned above, many of the Coalition's members are interested in developing additional projects, especially in Wyoming. If the Commission were to adopt the Coalition's recommendations, a few new projects would very likely be developed utilizing existing irrigation dams and canal drops.

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 advocates for PURPA policies that account for all these interests, and any changes adopted by Wyoming Public Service Commission (the "Commission") be narrowly tailored to resolve specific problems. Policy changes should not be unilaterally determined by the utility. The Coalition therefore wants to take this opportunity to recommend that Rocky Mountain Power's avoided cost calculation methodology should be based on the next renewable resource acquisition. In addition, the Commission's policy should allow a QF the opportunity to sell power based on either a renewable or non-renewable rate of its choosing.

Q. Please summarize Rocky Mountain Power's requests in this case.

A. Rocky Mountain Power has requested authority to revise its Schedule 37 standard rates for small QFs. According to the filing, the updated avoided cost pricing appears to be a routine price update that takes into account falling gas prices and is consistent with the 2017 Integrated Resource Plan ("IRP") submitted April 4, 2017. The Coalition would like to highlight, however, that for the first time ever the Company's IRP includes a resource acquisition that has not been included in the avoided cost calculation. Rocky Mountain Power has ignored the planned Wyoming wind resource acquisition, and claims that it is not a deferrable resource. In doing so, Rocky Mountain Power has manipulated its avoided cost filing to artificially lower its avoided cost prices and prevent eligible renewable resources from being fairly compensated.

Q. Please summarize your testimony.

A. The Coalition recommends that the Commission allow QFs the option to sell renewable power at fair, just and reasonable avoided cost prices based on the costs of Rocky Mountain Power's next planned renewable resource acquisition. QFs help defer Rocky Mountain Power's energy, capacity, and renewable resource needs, and should be fully compensated for the value of the energy that they cause the utility to avoid.

Specifically, the Coalition has a number of recommendations. First, the Commission should expand the eligibility for Schedule 37 to allow more cost-effective projects in Wyoming. Second, the Commission should reject the portions of Rocky Mountain Power's filing that constrain a QF's ability to establish a legally enforceable obligation. Third, the Commission should require Rocky Mountain Power to either provide a separate renewable rate or allow planned renewable resource acquisitions to serve as the basis of the Company's avoided cost rates. Finally, the Commission should clarify that all planned resource acquisitions, including cost-effective renewable resources, should be included in Rocky Mountain Power's avoided cost calculation.

II. SCHEDULE 37 ELIGIBILITY SHOULD BE EXPANDED

Q. Please summarize your recommendation regarding the eligibility for Schedule 37.

A. The Commission should expand the eligibility for Schedule 37 to allow a greater number of small and mid-sized generation projects to sell their power to Rocky Mountain Power, which is similar to other states. The current Wyoming Schedule 37 includes restrictions that excessively limit its applicability, which prevents cost effective renewable energy projects being developed because they need to negotiate their rates instead of being able to use published rates.

Q. Please summarize the current Wyoming Schedule 37.

A. In only Wyoming, Schedule 37 has limited applicability depending on the annual capacity factor of the resource. Specifically, Schedule 37's applicability is limited to two ways. First, only QFs 1 MW and below with an annual capacity factor of seventy percent or less are eligible for standard rates. Second, QFs 10 MWs and below can obtain the prices if they have an annual capacity factor greater than seventy percent. Seasonal hydro especially associated with summer irrigation systems, solar and wind generation do not have an annual capacity factor of greater than seventy percent, so that all of these facilities above 1 MW are ineligible for standard prices. Small projects that generate seasonally and contribute to a high peak load period have been ineligible to use Schedule 37.

The Wyoming Schedule 37 also includes another restriction that is unique to Wyoming. The standard prices are only available until 10 MW of system resources are acquired. I am not sure if this has been applied in the past or exactly what "system resources" are, but it is a restriction on the availability of the Commission approved rates.

Q. What are the eligibility terms for Schedule 37 in other states?

A. Most of the Company's other states have more favorable standard rates available to small facilities, and do not penalize those with low annual capacity factors, like seasonal hydroelectric projects. California, Idaho, Oregon, Utah, and Washington have eligibility based on project sizes between 3 and 10 MW, with no restrictions based on capacity factors.

Q. Is the standard 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 complex 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, 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 and risky in terms of whether such agreements can actually be completed in a timely manner. 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.

It is important to keep in mind that PPA negotiations are far from those of a normal arm’s length transaction. Establishing set prices protects QFs negotiating with unequal bargaining power and reduces negotiation costs imposed upon QFs. Smaller QFs are particularly vulnerable during negotiations because they are less likely to approach negotiations with a robust team and may not be able to sustain long-term negotiations. Thus, one of the goals should be to eliminate these market barriers and reduce transaction costs.

Q. Does this mean that larger projects do not face difficulties attempting to obtain contracts from utilities?

A. No. Although standard contracts and prices tend to focus on small QFs, larger projects also face difficulties negotiating with a potential business partner that does not want to buy their product. Utilities are obligated to purchase QF power and capacity whether the QF is eligible for standard contracts or not. Developing projects over standard contract size thresholds can be extremely difficult. Even assuming arguendo that larger QFs are more sophisticated or have a more robust staff to work on PPA negotiations, something which is not always true, there is still asymmetric availability of information, an unlevel playing field, and the economic incentive for utilities to refuse to purchase power from QFs. Larger QFs also often have no more bargaining power than small projects because their utility may be the only economic option to sell power given the lack of organized markets and a regional transmission organization, combined with a historical unwillingness of utilities to do business with independent producers.

Q. Why are you testifying about the problems faced by larger projects if this case is only addressing Schedule 37?

A. Because I did not want my focus on the difficulties faced by small QFs to mean that larger QFs do not also experience many of the same problems. It would be appropriate for the Commission to provide protections for larger projects at another time and in a different proceeding.

Q. What do you recommend?

A. The Commission should remove: 1) the capacity factor limitation on eligibility for standard prices up to 10 MW; and 2) the limitation on published prices being available only until 10 MW of system resources are acquired.

As explained above, standard prices provide the kind of regulatory certainty that can make or break both new and existing QF projects because of the difficulty negotiating with the utilities. The Commission should keep a size threshold, but increase the eligibility to all QFs regardless of their capacity factor. The current approach subjects smaller QFs to burdensome, complex, and one-sided negotiations with monopsony utilities that do not want to buy QF power. A larger size threshold for standard contracts will remove transaction costs and eliminate market barriers for QFs attempting to sell their power, and increase the ability of QFs to successfully negotiate contracts without unreasonable delays and obstacles.

III. THE ABILITTY TO ESTABLISH A LEGALLY ENFORCEABLE OBLIGATIONS SHOULD NOT BE CONSTRAINED

Q. What is the issue regarding legally enforceable obligations?

A. A QF has the right to receive a legally binding offer to establish a power sale to a utility pursuant to a contract or a legally enforceable obligation. While the Commission has attempted to streamline and reduce the opportunities for difficulties in the QF contract completion and negotiation process, the process sometimes results significant disputes between the QF and a utility. This is especially true when the avoided cost prices are expected to drop or lower prices already have been filed with the Commission.

Once discussions regarding a purchase contract reach an impasse due to the utility's unreasonable delays, unreasonable requirements or refusal to execute a contract, a QF has the legal right to assure its commitment to sell power to the utility under the then current prices and contract terms, which creates a legally enforceable obligation. The QF should then be paid those then current rates, even if the contract is not finalized. In this testimony, I propose specific revisions to the utilities' tariff which contains both the contracting process and avoided cost rates that allow a QF to create a legally enforceable obligation.

Q. Please explain what exactly is meant by a "legally enforceable obligation"?

A. QFs can sell their net output pursuant to a contract or a "legally enforceable obligation." 18 CFR 292.304(d); Order No. 69, FERC Stats. & Regs. ¶ 30,128, 45 Fed. Reg. 12,214 at 12,224 (1980). A legally enforceable obligation is broader than simply a contract between an electric utility and a QF and may exist without a contract. The concept of a legally enforceable obligation is intended to ensure that a QF can require a utility to purchase its power even if the utility has refused to enter into a contract.

A QF can enter into a legally enforceable obligation by committing itself to sell power to an electric utility. FLS Energy Inc., 157 FERC ¶ 61,211 at PP 23-25 (2016); Cedar Creek Wind, LLC, 137 FERC ¶ 61,006 at PP 36, 39 (2011). A utility cannot refuse to sign a contract so that a later and lower avoided cost is applicable. In other words, a legally enforceable obligation allows a QF to "lock in" current avoided cost rates, especially when a utility is delaying or otherwise imposing unreasonable terms and conditions.

Q. Why are you testifying about this issue now?

A. Because Rocky Mountain Power's current and proposed Schedule 37 includes language that is inconsistent with FERC's policies. Specifically, Schedule 37 states:

> The prices applicable to a Qualifying Facility over which the Commission has jurisdiction shall be those in effect at the time a written contract acceptable to the Company is signed on behalf of the Qualifying Facility and received by the Company at 825 N. E. Multnomah Street, Portland, Oregon, 97232, or such other address as the Company shall designate.

This language directly contradicts FERC's policies stating that requiring a QF to have a utility-executed contract or interconnection agreement in order to have a legally enforceable obligation is inconsistent with PURPA and its regulations. These types of requirements allow the utility to control whether and when a legally enforceable obligation exists, for example, by delaying the PPA negotiation process or interconnection studies, imposing unreasonable obstacles or refusing to execute a contract.

Q. Why is this issue important?

A. This issue is important because utilities, including Rocky Mountain Power, can impose roadblocks or obstacles on QFs seeking to obtain a contract. There are a number of common techniques. For example, a utility might impose pre-requisites to commencing the contracting process. This includes interconnection related issues, such as a requirement that the QF complete an interconnection agreement prior to beginning the PPA contracting process. Another example is a utility attempting to extend negotiations so a final draft agreement cannot be completed prior to new (lower) prices becoming effective. In addition, there can be a lack of willingness to complete or begin contract development if price changes are in progress. This is especially a problem when the maximum timeframes for completing an agreement can result in a final agreement being signed after new prices become effective. Most obstacles result from downward price changes mixed with the misalignment of the avoided cost prices update process. All these obstacles are subject to abuse and could be significantly improved upon with relatively minor changes to policy, practices and rules.

These delays and negotiation problems are particularly harmful when there is an upcoming avoided cost rate change. Utilities should not be allowed to refuse to sign a contract, delay the process, request inappropriate information, or impose unreasonable restrictions so that a later and lower avoided cost rate applies. The Commission should establish clear policies that, when negotiations stall or are delayed, a QF can enter into a legally enforceable obligation by committing itself to sell power to an electric utility. In addition, a QF should not lose its avoided cost prices after there is an agreement or the QF has committed itself to the fundamental contract and price terms, or the QF is simply waiting final approvals from management.

Q. What are the QF's options when a utility imposes unreasonable terms or conditions?

A. The QF can either agree to the utilities' unreasonable terms or conditions, or file a complaint. A complaint is an expensive and time consuming process that can delay when the QF can sell power to the utility. Therefore, in addition to the complaint's costs and uncertainty regarding the outcome, there can be significant lost sales when a complaint is filed. This is especially a problem when there is a pending rate decrease. The only economic option is often to sign the contract with unreasonable terms or conditions.

Based on the facts of the particular circumstances, a QF should be allowed to form a legally enforceable obligation prior to the date in which a utility provides a final power purchase agreement. In my experience, utilities can make minor revisions to power purchase agreements or impose new conditions in the negotiation process that can impose difficult burdens and slow the process. Once a QF has provided all the required information to the utility, and after the utility has provided a draft power purchase agreement, the QF should be allowed to obligate itself to sell power based on the then current avoided cost rates.

In addition, a QF should not be required to sign a utility's draft power purchase agreement to form a legally enforceable obligation. If the utility provides a draft power purchase agreement that includes provisions that are illegal or otherwise inconsistent with Commission policy, then the QF should have the right to obligate itself to sell power under the current avoided cost rates. The Commission may be required to resolve whether the terms of the power purchase agreement are consistent with law and policy, but a QF should not be required to agree to potentially illegal terms or conditions in order to demonstrate that it is willing to sell power under reasonable terms and conditions.

A QF should not be required to affirmatively demonstrate that a utility delayed the negotiation process or did not act in good faith. Such a demonstration can be very difficult to establish. In addition, there may be times when good faith negotiations simply fail to reach an agreement and there may be legitimate disputes that prevent the parties from reaching a signed, written contract. A QF should be allowed to obligate itself to sell power under the current avoided cost rates at reasonable terms and conditions, even if the parties cannot reach an agreement on a written contract.

Q. What are your specific recommendations to make the process more fair?

A. A QF should be allowed to create a legally enforceable obligation if the QF is unable to resolve outstanding issues after providng required information and negotiating in good faith with a utility. The utility's standard avoided cost rates have established negotiation processes, and a QF should be required to make a good faith effort to follow and comply with this process. For example, QFs should not be allowed to simply fill out and sign a draft contract in order to establish a legally enforceable obligation. QFs should be required to provide complete information so that the utility can prepare a draft contract. Assuming the utility timely provides a draft contract, then the QF should be required to make a good faith attempt to resolve any disputes regarding information, contract terms and conditions, etc.

A QF should be allowed to commit itself to sell power to the utility at the then current rates if negotiations reach an impasse after the QF complies with these initial requirements. The QF could then file a complaint to resolve the dispute, or continue negotiations with the utility on disputed non-price provisions without having to worry about a pending price change. Removing the risk of the QF losing the then current avoided cost rate will dramatically reduce the pressure on a QF to agree to an unreasonable or illegal contract in order to avoid a price reduction.

Q. Can you provide more specificity regarding your recommendation?

A. Yes. Exhibit 1, which is a revised version of Rocky Mountain Power's Schedule 37, provides an illustrative example. A QF is required to provide Rocky Mountain Power with specific information in order to obtain a project specific draft contract. It is reasonable to require the QF to provide certain minimum information. The utility should not be allowed to impose burdensome or overly stringent requirements. If Rocky Moutain Power has not requested additional or clarified information when it provides the draft contract, then the QF can request a final contract. More common, Rocky Moutain Power will request additional or clarified information. There can be disputes regarding contract terms in the draft contract, the reasonableness of project specific information, or other issues that are difficult to resolve.

My recommendation is that a QF should be able to create a legally enforceable obligation by committing itself to sell power under the then current rates if there are unresolved disputes after Rocky Moutain Power has provided (or should have provided) a draft contract. That commitment should identify the terms, conditions, and prices that the QF is obligating itself to deliver. In my experience, the QF and the utility will typically spend far more time exhaustively attempting to resolve any disputes. Sometimes it is clear that there are intractable disputes, especially if there is an upcoming rate change. After committing itself to sell power, the QF can then file a complaint, or continue negotiations on the disputed terms or conditions, without risk that they will loose the then current avoided cost rates.

Contract terms and conditions would be those ultimately agreed to or deemed reasonable by the Commission after a dispute resolution or complaint proceeding.

My recommendation also affords protections to the utilities from last minute efforts of QFs attempting to lock into prices before they change. This includes, for example, a minimum time prior to a price change that a proper and complete request for a contract be received by the utility. These and other approaches are all part of a revised contracting process that results in resolution of the legally enforceable obligation issue.

Specifically, my recommendation prevents QFs from attempting to form a legally enforceable obligation until they have provided information, received a draft contract and requests for additional information, and attempted to resolve the outstanding issues. It is also reasonable for QFs because it ensures that they are not pressured into agreeing to unreasonable terms, conditions, or requirements merely because they are afraid of losing their right to higher avoided cost rates.

IV. ROCKY MOUNTAIN POWER SHOULD OFFER A SEPARATE RENEWABLE AVOIDED COST PRICE STREAM

Q. What are avoided cost rates?

A. PURPA requires electric companies pay the "incremental cost" for energy produced by QFs. FERC regulations define the incremental costs as the cost to an electric utility, which but for the purchase from the QF, such utility would generate or purchase from another source. FERC relies upon the states to implement PURPA and to determine avoided cost rates. FERC allows states to make adjustments to the avoided cost rate to account for a QF's unique output and offer renewable pricing to reflect certain characteristics required by state policy.

Q. Should the Commission distinguish between renewable and non-renewable avoided cost rates?

A. Yes. All renewable QFs should be given the option to sell their renewable power to Rocky Mountain Power at a renewable avoided cost rate, whether the QF is above or below the size threshold for standard rates and regardless of resource type. The separate renewable avoided cost rate reflects the fact that renewable QFs help utilities meet more than just their load requirements and also help utilities comply with their state renewable portfolio standard ("RPS") requirement. Because some states require utilities to generate a certain amount of qualifying renewable power, it is reasonable to differentiate regardless of size between the cost of the utility's next planned renewable and non-renewable resources. Irrespective of RPS obligations, Rocky Mountain Power also has a need for a diverse resource portfolio, including both thermal and renewable resources. When a QF can defer or help Rocky Mountain Power avoid renewable resources that the Company is planning to acquire for economic or RPS purposes, it is reasonable to pay the QF based on the costs of those renewable resource acquisitions. Also, purchasing or developing more renewable resources should aid in making a long-term transition from problematic thermal resources.

When renewable QFs are willing to sell their output and cede their RECs to the utility, those QFs allow the utility to avoid building or buying renewable generation to meet their energy and capacity needs as well as their RPS requirement. A renewable avoided cost rate could be higher than the non-renewable avoided cost rate, as renewable generation has historically been more expensive than the non-renewable generation and the prices include an imputed value for RECs whose ownership is transferred to the purchasing utility when applying such renewable rates, or a renewable avoided cost rate could be lower than the non-renewable avoided cost rate, as renewable generation costs decline.

Q. Should the Commission allow QFs to choose between the renewable and non-renewable avoided cost rates?

A. Yes. QFs should be able to compare renewable and non-renewable avoided cost pricing before selecting the price stream that most closely resembles the type of power it is selling. When a renewable QF wishes to keep its RECs and only sell its net output to Rocky Mountain Power, then the QF should be paid a non-renewable rate based on the costs of the resource that it helps defer, including market purchases and thermal generation.

Q. Are there are other reasons to allow the QF the option to choose between a renewable and non-renewable rate?

A. Yes. Allowing renewable QFs to choose which avoided cost stream might better reflect the value of its resource. This is important to account for different types of renewable generation and QF business models, including the fact that some QFs may have already sold their RECs, or need to keep them to obtain financing. Having two different choices is more important as the utilities' resource plans change. For example, when the utilities are planning on acquiring non-renewable resources but not renewable resources, then the QF should be able to keep its renewable energy certificates and sell only its power to help the utility avoid its non-renewable resource need. The opposite is also true.

Without this optionality, then certain QFs may be unable to defer the utility's actual next resource when the utilities' renewable and non-renewable resource acquisition dates do not perfectly match. Allowing QFs to choose between the separate avoided cost rate streams is consistent with FERC policy allowing states to determine avoided costs associated with utility purchases of energy from generators with certain characteristics.

Q. Can a renewable rate work with Rocky Mountain Power's current Schedule 37 methodology?

A. Yes. Oregon uses a non-PDRR methodology similar to Wyoming's Schedule 37 methodology and has adopted renewable rates. Exhibit 2 to my testimony includes a copy of Oregon's version of Schedule 37. At the time the rates were set, the Oregon Commission determined that PacifiCorp's next planned renewable resource acquisition was 2028. During the years prior to 2028, a renewable QF selecting the renewable avoided cost rate is paid market prices and keeps their RECs. Starting in 2028, the renewable QF selecting the renewable avoided cost rate is paid a rate based on the next renewable resource acquisition in the IRP, which is currently a wind resource.

In Oregon, all renewable QFs can be paid a renewable rate, with each category of renewable resource (baseload, wind and solar) having a resource specific rate calculated with adjustments for integration costs and the generic resource capacity value. For example, baseload generation has no integration costs and a higher capacity factor, so their rates are correspondingly higher to reflect this higher quality of power. Similarly, solar generation also has a higher capacity value, which is reflected in rates that are higher than wind generation (but not as high as baseload generation). The specific Oregon rates should only be viewed for illustrative purposes because the underlying inputs and assumptions will be significantly different over time.

Q. Is Rocky Mountain Power receiving RECs from QFs in Wyoming?

A. Yes.

Q. What does Rocky Mountain Power Plan to do with the RECs it receives from QFs in Wyoming?

A. Rocky Mountain Power intends to keep any RECs generated from new renewable resources. Although Rocky Mountain Power's preferred portfolio does not reflect any RPS requirement or otherwise value renewable attributes, its IRP explicitly assumes that RECs associated with new renewable resources will contribute to meeting its RPS targets in the company's western states.

Q. So, does Rocky Mountain Power and its customers in Wyoming derive any benefits from RECs?

A. Yes. Rocky Mountain Power's IRP contemplates either using its RECs in Oregon, Washington or California (where it has RPS obligations), selling them to third-parties (and allocating part of those revenues to its customers), or using them to comply with Utah's RPS goal.

Q. Is Rocky Mountain Power compensating Wyoming QFs for those benefits?

A. No.

Q. What is the Coalition's position on REC ownership?

A. QFs should keep their RECs, unless the value of the power they are paid accounts for its renewable attributes. Therefore, if a QF is paid for power based on the costs of market purchases or a gas plant, then the QF should keep its RECs. If a QF is paid for power based on the costs of a renewable resource, then the QF should transfer its RECs to the utility.

Q. When the QF sells power under the renewable rate, should the QF cede the RECs in all years?

A. No. Generally, QFs should retain RECs during the Short Run period, that is the years prior to Rocky Mountain Power's next planned renewable resource acquisition date. This is because the avoided cost rates during those years are based on the value of market purchases, which do not include RECs.

Q. Please summarize your recommendation.

A. The avoided cost methodology could be used as is to provide both renewable and non-renewable avoided cost prices. The renewable price would be based on the next renewable resource and the non-renewable price would be based on the next non-renewable resource. A renewable QF should be able to choose between those two options, as long as it transfers its REC to Rocky Mountain Power in the years in which the prices are based on renewable proxy resource.

V. AVOIDED COST RATES SHOULD BE BASED UPON THE NEXT PLANNED RESOURCE ACQUISITION, WHICH IN THIS CASE IS A 2020 WYOMING WIND RESOURCE

Q. Is there any reason to revisit Rocky Mountain Power's avoided cost methodology now?

A. Yes. This is the first time that Rocky Mountain Power's has determined that a renewable resource is the company's least cost option. Rocky Mountain Power's filing suggests that it is following the avoided cost methodology approved by the Commission. But, according to Rocky Mountain Power's previous filing, the resource deficiency period and avoided capacity costs should be based on the next deferrable resource in the Company's most recent IRP or IRP update. Rocky Mountain Power has taken the position that its next planned resource is not deferrable and has therefore not included that resource in its avoided cost calculation. Rocky Mountain Power should not be permitted to unilaterally determine whether its next planned resource in the IRP is deferrable. Thus, the Commission should require Rocky Mountain Power to either offer a separate renewable avoided cost rate that is based upon the company's next planned resource or base its existing avoided cost rate upon the company's next planned resource, which is the Wyoming wind resource.

Q. What is the next avoidable resource, according to Rocky Mountain Power's filing?

A. According to Rocky Mountain Power, next deferrable resource is a simple cycle combustion turbine ("SCCT") in 2029.

Q. Which resource is the basis of Rocky Mountain Power avoided cost rates?

A. The current proxy resource is a combined cycle combustion turbine ("CCCT"). Rocky Mountain Power uses a CCCT, rather than a SCCT, because it believes that the SCCT is not a reasonable proxy due to certain operating characteristics and dissimilarities with QF resources. But, just as Rocky Mountain Power argues that the SCCT is not a good proxy, it should realize that the CCCT is also not a good proxy, especially as compared to its next planned resource acquisition (a wind facility), which may more closely align to QFs' operating characteristics. Rocky Mountain Power's use of the CCCT substitution supports the Coalition's recommendation to offer a separate renewable and non-renewable price stream so that QFs (rather than the Company) can determine which operating characteristics better match their own facilities.

Q. Is it appropriate for Wyoming QFs to be paid based on Rocky Mountain Power's next deferrable renewable resource, which happens to be Wyoming wind?

A. Wyoming resources should be paid rates based on Rocky Mountain Power's next planned resource acquisition, including Wyoming wind. Avoided cost prices for PacifiCorp have never been based upon a state-specific resources but the next avoidable resource in their system. Rocky Mountain Power's IRP has identified 1,100 MW of Wyoming wind resources that it will acquire by the end of 2020. This should be the date upon which Rocky Mountain Power is considered renewable "deficient" and Wyoming QFs paid capacity costs based on Wyoming wind generation, if they elect to sell their RECs.

Q. Why does Rocky Mountain Power claim that no Wyoming resources, including wind, should be paid for deferring this Wyoming renewable resource?

A. Because the Company states that these capacity additions cannot be delayed or scaled down as result of a QF resource addition. Rocky Mountain Power's position on the actual avoidable nature of these resources is untested, unproven, and was unilaterally determined.

Q. What is your response?

A. This is not how PURPA works. The question is not whether a single Wyoming QF can defer any particular resource, but what investments QFs in the aggregate will allow the utility to avoid. Even though small amounts of capacity provided from QFs taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions, the aggregate capability of such purchases may permit the deferral or avoidance of a capacity addition. The logical result of Rocky Mountain Power's argument is that Wyoming QFs would never be paid any capacity because no single Wyoming QF can displace a Wyoming power plant.

A number of examples illustrate this point. For example, small QF contracts and front office transactions are included in Rocky Mountain Power's load resource balance so as to avoid planning to construct or acquire duplicative facilities. Another example is how Rocky Mountain Power's current and proposed Schedule 37 methodologies work. A QF is paid for deferring its proportionate share of the costs of a large thermal gas plant in the deficiency period. There is no way a single 3 MW QF by itself will ever delay or scale down a 500 MW combined cycle combustion turbine plant. However, we assume that 500 MWs of small QFs could defer the construction of a new gas plant, and the utility would pay the QFs based on the avoided costs of this gas plant. Finally, assume that 1,100 MW of Wyoming QFs could be built at the same or lower cost as Rocky Mountain Power's Wyoming wind and transmission resources. It would be imprudent for Rocky Mountain

Power to build these 1,100 MW of wind generation and the associated transmission assets instead of purchasing 1,100 MW of Wyoming projects that are ultimately more cost effective.

Q. Is there any evidence that QFs are actually deferring acquisitions planned by Rocky Mountain Power?

A. Yes. First, the Company's last Schedule 37 filing was based on a plan to acquire a CCCT in 2027. The Company's current Schedule 37 filing is based on a plan to acquire a CCCT in 2029. The Company has not made any new major resource acquisitions since its last Schedule 37 filing, but has entered into new QF PPAs and purchased RECs from QFs since that time.

Q. Is there any evidence that QFs are actually deferring the currently planned Wyoming Wind acquisition?

A. Yes. Rocky Mountain Power has recently executed 320 MW of new wind resource capacity through QF PPAs. The Company has acknowledged that those recently executed PPA will reduce the amount of power acquired in its upcoming RFP. Rocky Mountain Power's response to Data Request 1.25 is attached as Exhibit 3. This is concrete, specific evidence that the Wyoming wind resource from the Company's 2017 IRP is in fact deferrable.

Q. What is the Coalition's position on Rocky Mountain Power's Short Run and Long Run dates?

A. The Short Run period should be set to 2020 to reflect the next planned resource acquisition. Rocky Mountain Power's filing relies upon legal fiction. The idea that its next resource acquisition is in 2029 is simply not accurate.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes

CERTIFICATE OF SERVICE

I hereby certify that, on this 6th day of November, 2017 the **RENEWABLE ENERGY COALITION TESTIMONY AND ATTACHMENTS OF JOHN R. LOWE** was served by electronic mail or U.S. Mail, addressed to the following:

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