BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED TERM OF PURPA POWER PURCHASE AGREEMENTS	))))))	DOCKET NO. 20000-545-ET-18 RECORD NO. 15133

DIRECT TESTIMONY OF JOHN LOWE ON BEHALF OF RENEWABLE ENERGY COALITION

Renewable Energy Coalition ("REC") submits the Prefiled Direct Testimony of John Lowe in this docket.

Dated this 19th day of April, 2019.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that on this 19th day of April, 2019, the **DIRECT TESTIMONY OF JOHN LOWE ON BEHALF OF RENEWABLE ENERGY COALITION** was e-filed with the Wyoming Public Service Commission and a true and correct copy was sent via electronic mail addressed to the following:

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IN THE MATTER OF THE APPLICATION	)	
OF ROCKY MOUNTAIN POWER FOR A	)	DOCKET NO. 20000-545-ET-18
MODIFICATION OF AVOIDED COST	)	
METHODOLOGY AND REDUCED TERM	)	RECORD NO. 15133
OF PURPA POWER PURCHASE	)	
AGREEMENTS	)	

Direct Testimony of John Lowe

On Behalf of

Renewable Energy Coalition

April 19, 2019

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED TERM OF PURPA POWER PURCHASE AGREEMENTS	))))))	**Docket No. 20000-545-ET-18 (Record No. 15133)**

AFFIDAVIT, OATH AND VERIFICATION FOR DIRECT TESTIMONY

STATE OF OREGON)
) SS:
COUNTY OF CLATSOP)

John R. Lowe, being fast duly sworn, on his oath states:

1. My name is John R. Lowe. I am the Director of the Intervenor Renewable Energy Coalition (the "Coalition"). I have been asked by the Renewable Energy Coalition to testify on its behalf.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, which has been prepared in written form for introduction into evidence in Docket No. 20000-545-EA-18.

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

4. Further Affiant sayeth not.

John R. Lowe
Renewable Energy Coalition
88644 Hwy. 101,
Gearhart, OR 97138

Subscribed and sworn to before me this 18th day of April, 2019.

OFFICIAL STAMP
YVETTE COOLEY
NOTARY PUBLIC - OREGON
COMMISSION NO. 950733
MY COMMISSION EXPIRES MAY 22, 2020

Notary Public

My Commission Expires: May 22, 2020

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 ("REC" or the "Coalition"). My business address is 88644 Hwy. 101, Gearhart, OR 97138

Q. Please state your background and experience?

A. In 1975, I graduated from Oregon State University 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 or services coordination to individual members related to power purchases, interconnections, and other interfaces with a purchasing utility such as electrical operation problems, metering, communications and billings.

Q. On behalf of whom are you appearing?

A. I am testifying on behalf of REC.

Q. Please describe REC and its members?

A. REC is an unincorporated trade association that is comprised of 35 members who own and operate over fifty qualifying facilities ("QFs") or are attempting to develop new QFs under PURPA in Oregon, Idaho, Washington, Utah, Montana and Wyoming. REC's members include irrigation districts, water and waste management districts, corporations, small utilities, and individuals with an interest in selling renewable energy to utilities –

who, absent PURPA, may have no viable mechanism to develop and sell the output of renewable energy projects.

Ted Sorenson of Sorenson Engineering who is testifying in this proceeding is a co-founding member of REC with me, and like other REC members such as Ecoplexus Cypress Creek Renewables, and Strata Solar are seeking to develop new QF projects in Wyoming. Shoshone Irrigation District, which owns and operates the Garland Canal project, is REC's sole operating Wyoming member with an operating project. The fact that the REC 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 including a few new small hydroelectric projects on exsiting irrigation distrcit systems.

Q. What are REC'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, policies, terms and conditions for QF projects and ratepayers. 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 Wyoming Public Service Commission (the "Commission") were to adopt the Coalition's recommendations, at least few new projects would have a reasonable opportunity to be developed utilizing existing irrigation dams and canal drops. In addition, Wyoming could see the development of additional solar facilities, which are currently being discriminated against under Rocky Mountain Power's pricing methodology.

The Coalition recognizes that PURPA must work to benefit all interested parties, including the utilities, ratepayers, and new and existing QFs of various sizes. REC advocates for PURPA policies that account for all these interests and that any changes adopted by the Commission be narrowly tailored to resolve specific problems. Policy changes should not be unilaterally determined by the utility.

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

A. Rocky Mountain Power proposes to reduce the contract term from twenty to seven years, a significant change in its Schedule 37 pricing methodology, other changes to the avoided cost price inputs and assumptions that would only offer avoided cost prices in limited circumstances, and changes to its Schedule 37 and 38 contracting procedures.

Q. Please summarize your recommendations.

A. First, I recommend that the Commission reject Rocky Mountain Power's proposal to lower the fixed price contract term from twenty years to seven years. Based on my years of experience, seven years of fixed prices especially resource sufficiency based market only prices, is inadequate to enable nearly all new QFs to obtain the financing necessary for construction and commencing operation or to plan and finance major upgrades to existing projects. My recommendation is that the Commission retain twenty-year fixed price terms.

Rocky Mountain Power is proposing to limit the availablity of most renewable resources from being paid a rate based on the capital costs of the next deferable resource. Rocky Mountain Power has proposed that only wind can defer wind, solar defer solar, etc. A renewable rate should be offered to all renewable QFs instead of limiting renewable rates to only those QF resource types of the same resource type identified in Rocky Mountain Power's Integrated Resource Plan ("IRP"). If Rocky Mountain Power has a renewable resource need for wind in 2020, then other generation types like hydroelectric or solar generation can defer that resource need and should be appropriately compensated for the value of their renewable power. This is different from Rocky Mountain Power's proposal, which limits renewable rates only to "like" resources.

Third, a renewable QF under Schedules 37 and 38 should have the option of being paid based on either a renewable avoided cost price or a non-renewable avoided cost price. I recommend allowing a QF the opportunity to sell power based on either a renewable or non-renewable rate of its choosing, which would allow the QF the choice: 1) to keep its renewable energy certificates and sell Rocky Mountain Power only its net output, and be paid based on the next deferrable non-renewable resource; or 2) sell both its renewable energy certificates and net output, and be paid based on the next deferrable renewable resource.

Fourth, a QF should keep the renewable energy certificates, unless the value of the power they are paid accounts for its renewable attributes.

Fifth, Rocky Mountain Power should only assume that a reasonable percentage of QFs that enter into contracts actually get constructed. Based upon my many years of experience and input for current REC members, for the purpose of this case, a 75% completion rate is an much needed improvement and could be reasonable. However, actual analysis of historical data could to demonstrate a significantly lower rate. In any event a 100% completion rate assumption is entirely unreasonable and without any foundation of evidience. This is important because Rocky Mountain Power assumed 100% of contracted QFs completion rate, artificially reduces avoided cost prices and thus produces inaccurate prices. This in turn begs the question of why a price methodology change for the purpose of improving accuracy while applying a completion rate assumption that does the opposite.

Sixth, 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, as explained above, Rocky Mountain Power proposes that the term be interpreted to mean once it enters into 10 MWs of Schedule 37 contracts, then all other QFs above 100 kW need to negotiate their rates. I recommend that this cap be eliminated, or in the alternative increased to 100 MW. No project as small as 100 kw should have to be exposed to non-standard prices and contracts.

Seventh, for the first time Rocky Mountain Power proposes that the Schedule 38 negotiation process apply to Schedule 37 QFs. Small QF contracts are far more streamlined and less difficult to negotiate (in fact, Rocky Mountain Power has standard contract forms and there should be no need for any substantive negotiations), and prices are published (which requires no negotiations or analysis). Therefore, the Commission should reject Rocky Mountain Power's request to apply the Schedule 38 process to Schedule 37 QFs and should approve less onerous and more expedited processes for entering into Schedule 37 contracts.

Eighth, the Commission should continue to use Rocky Mountain Power's Grid/Proxy methodology for setting small Schedule 37 QF prices, rather than the Proxy/PDDRR methodology used for Schedule 38 QF prices. Rocky Mountain Power's avoided cost prices for Schedule 37 are already too low, and fail to fully compensate QFs for their full capacity and energy value. Rocky Mountain Power's proposal will further exacerbate this inequity and result in challenges to and less transparency in the determination of contracted prices.

Ninth, Rocky Mountain Power's proposal that a QF needs to select a commercial operation date ("COD") 30 months from contract execution should be rejected in favor allowing the QF the greater of four years (48 months) or the earliest in-service-date Rocky Mountain Power identifies in its own interconnection study. Rocky Mountain Power is informing QFs that it might take 5-6 years (60-72 months) to interconnect them. This means that 30 months is far too short a period of time to reach COD when the same company (Rocky Mountain Power) refuses to, or is unable to, process the QF's interconnection request within that timeframe. A QF should not be placed in a "Catch 22" situation in which it is required to pick a COD which less time than Rocky Mountain Power can interconnect the facility. This is just one example of how Rocky Mountain Power has weaponized the transmission and interconnection process to avoid its PURPA mandatory purchase obligation.

Tenth, Rocky Mountain Power's tariffs should reflect that the current policy of the Federal Energy Regulatory Commission ("FERC") is that neither a state or a utility can impose barriers to the formation of a legally enforceable obligation, and that a QF can lock in avoided cost rates and contract terms even if a utility refuses to enter into a contract or otherwise delays or imposes unreasonable restrictions. I propose revisions to Schedule 37 and 38 which update the tariff to be consistent with FERC policy.

Q. Please provide your broad observations regarding Rocky Mountain Power's filing.

A. Rocky Mountain Power's proposal makes me wonder what problem they are trying to solve, or what problems they may be trying to create to slow down or stop renewable non-utility owned projects. Rates are already at historic lows, and REC fails to see any reason to make changes that make it even more difficult to develop new QFs in Wyoming.

Rocky Mountain Power complains that PURPA is a 40 year old law from a different time and believes that it should be repealed. Nothing can be further from the truth, especially for small projects. Rocky Mountain Power won the vast majority of the "bids" in its last RFP and there are almost no small scale projects in Wyoming, despite significant opportunities in terms of natural resources. Rocky Mountain Power remains a vertically integrated monopoly and wields its discriminatory powers ruthlessly to puts its competitors out of business, especially projects that have no other economic opportunities to sell their power.

Rates are at historic lows for a number of reasons, including: 1) Rocky Mountain Power has eliminated capacity payments during the resource sufficiency years so that

QFs are only paid market rates; and 2) Rocky Mountain Power has proposed sufficiency periods of more than a decade for certain resource technologies, even though the Company is planning on significant resource acquisitions in the next few years (over $3 billion in investments in new Wyoming wind generation, repowered wind, and new Wyoming transmission to wheel the new Wyoming wind). In short, Rocky Mountain Power is in a major new-build cycle, but is asking the Commission to further lower avoided cost prices. This is resulting in a massive amount of new generation serving customers, but with nearly all of it being either owned or operated by Rocky Mountain Power. This is not in the best interests of ratepayers because diversity of ownership offers unique benefits to customers, and competition results in lower costs.

Overall, REC wants to take this opportunity to recommend that Rocky Mountain Power's proposed changes their avoided cost calculation methodology be adopted, but only with specific revisions to ensure that it more accurately reflects both the value and costs of the utility's next deferrable resource. REC 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. 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.

Q. Is REC sponsoring other witnesses?

A. Yes.

Drs. Marc Hellman and Lance Kaufmann are presenting testimony recommending:

- Twenty year contract terms should be retained, but if contract terms are reduced, then QF contract capacity payment calculations should assume a twenty-year contract term.

- That Rocky Mountain Power's proposal to limit renewable avoided cost rates to only "like" resources of the same type of technology as Rocky Mountain Power is planning to acquire in its IRP is unreasonable. Limiting avoided cost prices by type does not adequately compensate renewable QFs for their renewable power. Revising the current Schedule 37 Grid/Proxy methodology to allow for a renewable rate is easy because it simply replaces the thermal generation unit during the resource deficiency period with the next deferrable renewable resource. This approach could easily calculate resource specific rates for baseload, wind and solar using the capacity value and integration costs from Rocky Mountain Power's IRP. Revising the Schedule 38 Proxy/PDDRR methodology to develop a renewable rate for all renewable resources can also be done simply, and Drs. Hellman and Kaufmann testimony explains how this would work. Drs. Hellman and Kaufmann also address why it is unreasonable to limit renewable rates to only "like" resources.

- Rocky Mountain Power's proposed changes to the definition of peak/off peak and seasons is premature, inappropriately based on the California market rather than Rocky Mountain Power's system, and not well supported.

- If the Commission is inclined to have Schedule 37 Customers over 100 kW revert to Schedule 38 when a threshold of new QFs MW amount is reached, the RMP recommended 10 MW threshold should be revised to 100 MW.

- RMP should assume a maximum of 75 % of executed contracted QFs will operate when determining the need for capacity and amounts met by QFs with executed contracts but not yet operating. Full demonstration of the actual historic and current completion rate is recommended if any completion rate above 75% is applied.

- RMP's proposed tariff language on Page 37-3 should be revised from, "...until Schedule 37 prices are updated and approved by the Commission" to "until the Commission takes final action on any Company filing to revise Schedule 37 pricing."

REC is also sponsoring testimony from Ted Sorenson, who owns and operates Sorenson Engineering, which is a co-founding member of REC. Mr. Sorenson has extensive experience developing small hydro-electric projects most of which are associated with irrigation systems or existing dams, believes Wyoming is a prime location for the installation of these small scale projects that provide benefits to ratepayers, local communities, irrigation districts and the environment. Wyoming, however, is not "open for business" sufficient to allow the development of significant new small hydroelectric projects, and needs to adopt more favorable pricing that accurately reflects actual avoided costs as well as maintain long-term fixed price contracts. Mr. Sorenson address the opportunities for new hydro-electric development in the state, the devastating impact of lowering contract terms to seven years, and that that renewable resources of all types should be allowed to be paid rates based on the next major resource of any type.

REC is also sponsoring testimony from Trent Reed, who is the General Manager of Shoshone Irrigation District.

II. TWENTY YEAR FIXED PRICE CONTRACT TERMS SHOULD BE RETAINED

Q. What is the Commission's current policy on contract duration?

A. Twenty year fixed price terms.

Q. Do you agree with PacifiCorp's recommendation to lower the contract term length to seven years?

A. No. Seven years fails to account for the needs of QFs, including the need to obtain financing for their projects. The Commission should maintain twenty year contract terms.

Q. Please explain why a fixed long term contract is important for QFs.

A. Longer term agreements are needed to meet financing and long-term planning needs. New projects certainly need the longer term in order to meet debt requirements. Even existing projects require long term agreements for system improvement projects and planning. This is especially true for QFs that are water systems, such as irrigation districts. There are other reasons why longer-term agreements are necessary, one of which is the avoidance of market based energy only prices during periods of resource sufficiency.

Q. Please explain the importance of contract terms and QF financing under PURPA.

A. For PURPA to be successful, QFs need to be able to obtain financing in order to construct their facilities and to obtain financing they need a fixed price that the lender or other source of capital can count for a minimum period of time. Unlike utilities like Rocky Mountain Power, QFs are not guaranteed a rate of return on their activities generally or on the activities related to the sale of power to the utility. QFs must rely on long-term contracts containing fixed contractual rights and prices that are not subject to changes over time to obtain financing for such facilities operating in a market controlled by monopoly utilities.

Q. Have other states looked at reducing contract terms?

A. Yes, and I am not aware of any state which has adopted short contract terms that resulted in meaningful QF development. Idaho reduced contract terms to two years for new wind and solar QFs, and has significantly reduced if not eliminated new wind and solar development. In Washington, PacifiCorp only provided five years of fixed prices, which resulted in only three currently operating QF projects in their service territory over about forty years.

Montana recently lowered the contract term to ten years and the fixed price term to five years with automatic adjustments for the last five years. A Montana judge recently concluded that the Montana Public Service Commission's decision lowering contract terms failed to provide evidence that shorter terms would provide QFs with sufficient certainty with regard their potential return on investment or to enhance their economic feasibility. The judge concluded that the Commission's decision was arbitrary and unreasonable.

Q. Do short contract terms impose unnecessary and unreasonable burdens on both QFs and utilities?

A. Yes. 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 seven years. Requiring the utilities to renegotiate QF contracts every seven years, for example, would be costly for the utilities. These unnecessary costs would be passed on to ratepayers.

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

A. Yes. Rocky Mountain 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 seven years, then projects will no longer receive capacity payments or only receive a very limited number of years of capacity payments because the next capacity deficit period will normally be more than the contract term.

Q. Can you provide an example?

A. Yes. Under Rocky Mountain Power's proposal, QFs will not be paid for capacity if they enter into a contract when the next resource acquisition is in longer than the contract term. For example, assume that Rocky Mountain Power is planning its next resource acquisition in seven years (2027). Under Rocky Mountain Power's proposal, a QF that enters into a new seven-year contract in 2027 will not be paid for capacity during the entire contract term. In 2027, Rocky Mountain Power will have a new IRP, which might not be planning on a new resource for more than seven 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 seven-year contract in 2027, 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 Rocky Mountain 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 Rocky Mountain Power's proposed seven year contract term. If contract terms are shortened to even 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.

III. RENEWABLE RESOURCE RATES SHOULD BE AVAILABLE UNDER BOTH SCHEDULE 37 AND SCHEDULE 38

Q. What are avoided cost prices?

A. PURPA requires electric companies to 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 prices. FERC allows states to make adjustments to the avoided cost price 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 prices?

A. Yes. All renewable QFs should be given the option to sell their renewable power to Rocky Mountain Power at a renewable avoided cost price, whether the QF is above or below the size threshold for standard prices, and regardless of resource type. The separate renewable avoided cost 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 on acquiring 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 renewable energy certificates 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 requirements. A renewable avoided cost price could be higher than the non-renewable avoided cost price, as renewable generation has historically been more expensive than non-renewable generation and the prices include an imputed value for renewable energy certificates whose ownership is transferred to the purchasing utility when applying such renewable price, or a renewable avoided cost price could be lower than the non-renewable avoided cost price, as renewable generation costs are currently quite low.

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

A. Yes. QFs should be able to compare renewable and non-renewable avoided cost pricing before selecting the price stream that most closely resembles their project. When a renewable QF wishes to keep its renewable energy certificates and only sell its net output to Rocky Mountain Power, then the QF should be paid a non-renewable price based on the costs of the resource that it helps defer, including market purchases and thermal generation. Generally, renewable energy certificates should be retained by the QF during the years prior to Rocky Mountain Power's next planned renewable resource acquisition date because the avoided costs during those years are based on the value of market purchases, which do not include renewable energy certificates.

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

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 renewable energy certificates, 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, 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 price 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 price work with Rocky Mountain Power's current Schedule 37 methodology?

A. Yes. PacifiCorp in Oregon uses a non-PDRR methodology for smaller QFs, which is similar to Wyoming's Schedule 37 methodology, and has adopted renewable prices. Exhibit B to my testimony includes a copy of PacifiCorp's Oregon's version of Schedule 37. At the time the prices were set, the Oregon Public Utility Commission determined that PacifiCorp's next planned renewable resource acquisition was 2021. During the years prior to 2021, a renewable QF selecting the renewable avoided cost price is paid market prices and keeps their renewable energy certificates. Starting in 2021, the renewable QF selecting the renewable avoided cost price is paid based on the next renewable resource acquisition in the IRP, which is currently a wind resource.

In Oregon, all renewable QFs have a renewable price option, with each category of renewable resource (baseload, wind and solar). Each has a resource specific price 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 price 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 price should only be viewed for illustrative purposes, because the underlying inputs and assumptions will be significantly different over time.

Q. Can a renewable price work with Rocky Mountain Power's proposed Schedule 38 methodology?

A. Yes. I am not an expert with Rocky Mountain Power's PDDRR methodology, but Coalition witnesses Drs. Hellman and Kaufmann explain how this would be implemented. While it might be workable, it is un-necessary and overly complicates the determination of contract prices and the contracting process for small projects. What is critically important for both Schedules 37 and 38 is that any renewable resource type be allowed to defer Rocky Mountain Power's next renewable resource acquisition, just as how today any renewable resource type is allowed to defer Rocky Mountain Power's next thermal resource acquisition. Under Rocky Mountain Power's proposal, a solar, biomass, waste generation or hydro QF could never be paid a renewable price if the Company is not planning on building and owning this type of generation in the near future. Purchases from these various renewable resources can help Rocky Mountain Power avoid its next planned wind generation now and should have the option to be paid renewable rates now.

Q. Should the PDDRR configuration be revised?

A. Yes. Although Rocky Mountain Power claims that the PDDRR methodology is more accurate, it also suggests that the PDDRR methodology cannot accurately calculate capacity contributions for different types of resources. To resolve this issue, Rocky Mountain Power suggests the Commission approve its "like-for-like" limitations. The REC disagrees. As the testimony from Drs. Helmman and Kaufmann describe, Rocky Mountain Power can configure the PDDRR methodology to work for all types of resources, and should be required to do so. Otherwise, the "like for like" approach becomes a clever way of avoiding or minimizing Rocky Mountain Power's PURPA purchase obligation and highly limits the renewable technologies that can be built.

Q. Does this mean the proposed PDDRR configuration would not improve accuracy?

A. Yes. According to Rocky Mountain Power, the PDDRR method has limited effectiveness because it only accurately captures the impact of a QF when that QF is the same type (or has the same operating characteristics) as the company's next planned resource. Accurate avoided cost prices, however, should be available for all resource types. Thus, Rocky Mountain Power's configuration of the PDDRR method is not more accurate than the former method because it fails to produce accurate avoided cost price for all resource types. The more simple proxy method can be easily configured to ensure accurate avoided cost prices for all resource types.

Q. Why does Rocky Mountain Power claim that no Wyoming solar or hydroelectric resources, should be paid for deferring Rocky Mountain Power's next renewable wind resource?

A. Because the Company states that these capacity additions cannot be delayed or scaled down as result of a QF resource addition. Their position on the actual avoidable nature of these resources is untested and unproven.

Q. What is your response?

A. This is not how PURPA works. The question is not whether a single Utah QF can defer any particular resource, but what investments from 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 no QF should ever be paid any capacity because no single QF can displace a Wyoming power plant.

A number of examples illustrate this point. First, 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 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 pay the QFs based on the avoided costs of this gas plant.

IV. RENEWABLE ENERGY CERTIFICATE OWNERSHIP

Q. What is your position on REC ownership?

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

V. ROCKY MOUNTAIN POWER'S QF CONTRACT COMPLETION

Q. How do QFs with executed contracts impact avoided cost prices provided to QFs which have not yet executed contracts?

A. QFs that have executed contracts with Rocky Mountain Power are counted as meeting any resource need, on a like-for-like basis, and impact the evaluation as to whether any capacity payment would be available. The modeling assumes that each QF that requests pricing will displace resources with the highest variable costs, which means that each avoided energy costs declines accordingly. Thus, the more QFs that have entered into contracts and are included in Rocky Mountain Power's models, the lower the prices offered to the next QF seeking a contract.

Q. Do you agree with Rocky Mountain Power's assumption that 100% of the QFs that have entered into contracts will become constructed?

A. No. By assuming that every single executed contract will result in corresponding power sales, Rocky Mountain Power artificially lowers its avoided cost prices.

Q. What portion of the QF queue should be used to calculate avoided cost prices?

A. A more reasonable position would be to use the historic percentage of QFs that are constructed as compared to the entire queue, or certain completion milestones that show a proposed project is likely to be constructed. Drs. Hellman and Kaufmann recommend that 75% of contracted QFs be assumed to operate, and based on my years of experience, this appears to be the high end of a reasonable percentage.

VI. SYSTEM RESOURCE CAP

Q. Does Schedule 37 include limitations on the number of QFs that can take service under it?

A. Yes, although the language is unclear as to what it means. The current tariff says: "These prices will only be applied to Qualifying Facility resources over which the Commission has jurisdiction that enter into contracts with the Company until 10 megawatts of system resources are acquired."

Q. What does Rocky Mountain Power propose?

A. Adding language so that, after acquiring 10 MW of Firm Power under Schedule 37, pricing for QFs larger than 100 kW will be in accordance with Schedule 38 until prices are updated and approved by the Commission.

Q. Do you agree with this recommendation?

A. No, Wyoming is the only state that would impose such an unreasonably low limitation on eligibility for Schedule 37 prices. As Drs. Hellman and Kaufmann recommend, if the Commission is inclined to have Schedule 37 Customers over 100 kW revert to Schedule 38 when a threshold of new QFs MW amount is reached, then the Rocky Mountain Power recommended 10 MW threshold should be revised to 100 MW.

VII. SCHEDULE 37 NEGOTIATION PROCESS

Q. Does Wyoming currently proscribe a process for negotiation of Schedule 37 contracts?

A. Not that I am aware of. Rocky Mountain Power claims that it uses its Schedule 38 process for negotiating Schedule 37 contracts.

Q. Do you agree?

A. I have no information to disagree; however, as there are almost no Schedule 37 QFs in Wyoming, then potentially no or very few QFs actually use Schedule 37.

Q. Should Schedule 38's process be used for Schedule 37?

A. No. When I worked for PacifiCorp, I was the person who developed and drafted the original version of Schedule 37. Schedule 37 is intended to be used for smaller QFs that require fewer negotiations regarding contract forms and no negotiations over price. Rocky Mountain Power has contract forms that it is required to use for Schedule 37 QFs in Oregon and has established forms for small QFs that is uses in its other states. The contract negotiation process should be very streamlined and need very little time. The prices are published and there is no need to negotiate the prices. Therefore, Schedule 37 contracts generally are and should be able to be completed in far less time that a Schedule 38 contract. I have attached Oregon's version of Schedule 37, which includes more appropriate informational requirements and timelines for smaller QFs, and I recommend that those informational requirements and timelines be used here in Wyoming.

VIII. <u>SCHEDULE 37 PRICING METHODOLOGY</u>

Q. Should Rocky Mountain Power change its Schedule 37 methodology?

A. No. Schedule 37 is only limited to 1) Qualifying Facilities with a historic or projected annual capacity factor of up to 70%, and a design capacity of up to 1 MW; 2) hydro projects with design capacity up to 5 MW; and 3) hydro or other projects with a historic or projected annual capacity factor of greater than 70%, up to a maximum of 10 MW of average monthly capacity and associated. There are very few Schedule 37 projects in Wyoming at this point, and I fail to see why the Commission should make unnecessary changes that further hinder the ability of these projects to be constructed. Drs. Hellman and Kaufmann address this issue in more depth. Schedule 37's recent improvements in eligibility would likely be effectively wiped out by requiring the application of Schedule 38 to small projects.

IX. GENERATOR INTERCONNECTIONS AND COMMERCIAL OPERATION DATES

Q. Has Rocky Mountain Power proposed limitations on when QF commercial operation date ("COD") can be selected?

A. Yes, Rocky Mountain Power has added a significant limitation with specific tariff provisions stating that QF COD (or the start of the delivery term of subsequent PPAs for existing QFs) must not exceed 30 months from the PPA execution date and that QFs must provide project development security within 30 days of its PPA being filed with the Commission.

Q. What do you recommend?

A. A QF should be able to select a COD that is the greater of: 1) four years from contract execution; or 2) the amount of time that PacifiCorp says it will take to complete any interconnections to match the COD.

Q. Is the Rocky Mountain Power transmission/interconnection process relevant to the selection of the appropriate COD?

A. Yes, Rocky Mountain Power has weaponized the transmission and interconnection process almost to perfection in its efforts to shut down and refuse to purchase power from QFs. This has been accomplished by creating conflict between the maximum time to allow for COD and the minimum time RMP may require for interconnection.

Q. Please provide some background on the interconnection and transmission study process.

A. For those not familiar with the Federal Energy Regulatory Commission jurisdictional interconnection process, the first step can be either a Feasibility or System Impact Study.

The developer and the interconnected utility enter into an agreement to conduct the study, which is called a "System Impact Study Agreement." This study has timelines for payment by the developer and completion of the study by the utility. After the developer and the utility enter into this agreement, the utility conducts the study and reviews the adequacy of its transmission or distribution system to accommodate the new generation and identifies what additional costs may be incurred to provide service. At the completion of the System Impact Study, the developer and the utility must enter into a new contract to conduct a new study, which is the "Facilities Study Agreement." The Facilities Study Agreement also includes timelines for payment and the completion of the study. The Facilities Study itself is more granular and is a real engineering study designed to determine the required modifications to the system, including the cost and scheduled completion date necessary to provide service. After these timelines and costs are identified in the Facilities Study, then the utility and developer negotiate an actual Interconnection Agreement to construct and pay for the interconnection to the utility's system.

Q. Are there often delays in this process?

A. Yes. The process, even when moving perfectly, can be cumbersome and time consuming, and it is not uncommon for there to be significant delays completely outside the control of the developer. I understand that interconnection customers on RMP's system are experiencing unprecedented delays, and that their interconnection requests have not advanced through the normal interconnection study process in a manner consistent with the Company's Open Access Transmission Tariff ("OATT") timelines.

Interconnection customers are simply not receiving the required explanation of the reasons why additional time is required, an estimated completion date, or even when their studies will begin to move forward. Some of these delays may exceed one year past the requirements in the OATT.

Based on publicly available information, it appears that in 2017, 153 projects submitted interconnection requests. Of those projects, 80 were withdrawn or granted an interconnection agreement. Only 7 have been issued Facilities Studies, 15 have been issued a System Impact Study, and one a Feasibility Study. While there may be some delays associated with the interconnection customer, there appears to be 50 projects from 2017 that apparently have not had any tangible action from the utility. Similarly, since the beginning of 2018, 115 projects have submitted interconnection requests. Of those projects, 17 were withdrawn or granted an interconnection agreement, one has been issued a Facilities Study, four have been issued System Impact Studies, and three Feasibility Studies. In 2018, the two projects that submitted interconnection requests and received interconnection agreements are both very small generators that are being processed via an expedited process and are not representative of the delays experienced by the majority of generators that are being processed under the FERC SGIP and LGIP. It appears that many of the executed interconnection agreements in 2017 may also have been small generators processed using more expedited procedures. There have been 89 projects submitted after January 1, 2018 that received no tangible action. We may be in a period of unprecedented interconnection delays, which could significantly limit the ability of QFs to sell power to Rocky Mountain Power or meet CODs established in power purchase contracts.

Q. Can you provide additional details regarding what a QF must provide to obtain a Large Generator Interconnection Agreement ("LGIA") from Rocky Mountain Power?

A. Yes. The LGIA is the last step in the interconnection process, and it provides the timeline and costs for the QF to be fully interconnected and sell power to the utility. Section 46.3 of PacifiCorp's OATT requires a QF to produce one of the following before it is able to execute an LGIA: 1) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; 2) the execution of a contract for the supply of cooling water to the Large Generating Facility; 3) execution of a contract for the engineering for, procurement of major equipment for, or construction of, ("EPC Contract") the Large Generating Facility; 4) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or 5) application for an air, water, or land use permit.

A wind or solar QF can only produce the last three documents in order to satisfy the OATT requirements. These cannot be provided so long in advance. An EPC Contract cannot be reasonably executed 3-6 years in advance of commercial operations, and permits cannot be applied for that far in advance because they will likely expire before you break ground. If Rocky Mountain Power refuses to negotiate and enter into a PPA in more than 30 months, then there is simply no way for the QF to even obtain a LGIA.

Q. How does this relate to PPA negotiation process?

A. Rocky Mountain Power won't execute a contract prior to the COD identified in a transmission study that it performs. A QF can do everything in its power to complete its project on a timely basis, but Rocky Mountain Power will not give the QF a contract because Rocky Mountain Power cannot guarantee that Rocky Mountain Power can interconnect the QF in 30 months.

Q. What do you recommend?

A. Because Rocky Mountain Power itself often controls the time upon which a project can be constructed, then I recommend that the QF be able to select a COD which is at least as far out as Rocky Mountain Power's interconnection study shows that COD can be achieved. So, if Rocky Mountain Power's transmission study says that the interconnection will be complete in 36 months, then the QF should be able to select a COD of at least 36 months.

Q. Have other states concluded that a QF should have a reasonable amount of time before contract execution and commercial operation date?

A. Yes. In Oregon, all parties, including PacifiCorp, agreed that QFs should have the right to select a period of up to three years, and should be able to demonstrate that a longer period is warranted under certain circumstances.[1] In addition, the QF is entitled to a one year cure period if they miss their COD. Allowing too little time between contract execution and delivery can create a barrier for QFs because they generally cannot obtain financing for a new project until after they have executed a PPA. This means that QFs

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[1] *Re Commission Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 15-130 at 2 (April 16, 2015); OAR 860-029-0120(4).

must wait for execution of a standard contract before commencing many of the steps that are necessary to bring a resource on line. Oregon's policy was adopted in 2015, before Rocky Mountain Power's interconnection and transmission reached its current situation in which Rocky Mountain Power has experienced an unprecedented level of interconnection delays. Given that conditions are worse, even additional time is warranted.

Q. Can existing projects require as much time as new projects between the time of executing a power purchase contract (replacement contract) and the new power delivery date?

A. Yes. In Oregon both new and existing QFs have the same period of time between the signing of a new contract or replacement contract and the commencement of power deliveries under such contract.[2]

Q. Why?

A. Existing projects also may need a significant period of time between execution of a new contract (replacement contract) and expiration of their current contract. Many existing projects have been operating for years, and they often require upgrading of their equipment and facilities, especially interconnection facilities and equipment. These investments require study, planning, financing, and construction similar to those of new projects. This means that these QFs need to enter into new PPAs well in advance of the expiration of the current contract because the interconnection process, even for existing facilities, can take multiple years. Existing QFs often must first enter into a new power

[2] OAR 860-029-0120(4).

purchase agreement to obtain financing for both the interconnection and facility construction, and thus they too can experience a delay between when they sign an agreement and when they become "operational" under that contract.

Given that interconnection process has become so delayed, I recommend that the Commission provide all QFs with the right to select a COD four years from contract execution or the date upon which the utility can interconnect them. Furthermore, that this time-frame be considered as a reasonable advance period for entering into a replacement contract.

Q. Should QFs be allowed reasonable cure periods?

A. Yes. For missing their COD, I recommend that a QF be allowed a one year cure period as a matter of right. A QF should be able to obtain a longer period if there are delays caused by the utility, including transmission and interconnection delays beyond what was estimated at the time that the QF signed its PPA.

X. <u>THE ABILITY TO ESTABLISH A LEGALLY ENFORCEABLE OBLIGATIONS SHOULD NOT BE CONSTRAINED</u>

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 potential difficulties in the QF contract completion and negotiation process, the process still can result in 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 prices, 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 prices 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."[3] 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.[4] 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 prices, especially when a utility is delaying or otherwise imposing unreasonable terms and conditions.

Q. Why are you testifying about this issue now?

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[3] 18 CFR 292.304(d); Order No. 69, FERC Stats. & Regs. ¶ 30,128, 45 Fed. Reg. 12,214 at 12,224 (1980).

[4] *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. 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.

Q. What does this language mean?

A. It appears to mean that, before a QF can "lock" in rates or form a legally enforceable obligation, the QF needs to provide a contract "acceptable to" Rocky Mountain Power. A QF does not need to sign a contract that Rocky Mountain Power agrees with to form a legally enforceable obligation, because that would provide the utility with the discretion over whether such an obligation is formed. 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 utilties, including Rocky Mountain Power, can impose roadblocks or obstalces 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 price 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 price 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 price.

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 prices. 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 prices 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 prices 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 prices 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 price 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 prices. 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 prices.

Q. Do your concerns also apply to Schedule 38?

A. Yes, I only used Schedule 37 for the sake of brevity. The above testimony also applies to Schedule 38 as well.

XI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes it does.