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

BRIEF OF RENEWABLE ENERGY COALITION

I. INTRODUCTION

Renewable Energy Coalition ("REC"), pursuant to Section 113 of the Rules of the Wyoming Public Service Commission ("WPSC" or "Commission"), hereby respectfully files this Brief in the above-captioned matter. REC urges the Commission to retain twenty-year contract terms to ensure that most Wyoming qualifying facilities ("QFs") will not be arbitrarily prevented from obtaining necessary financing for development and equipment upgrades, and to offset periods of low prices during early contract years. The Commission should also reject RMP's "like for like" proposal and instead direct RMP to provide non-renewable and renewable pricing options from which the QF can select. Finally, the Commission should require RMP to accurately price QF capacity and reject RMP's proposals to apply Schedule 38 processes and prices to Schedule 37 projects.

The Federal Energy Regulatory Commission's ("FERC's") regulations and policies under the Public Utility Regulatory Policies Act ("PURPA") require "long-term contracts" that allow QFs an opportunity to obtain financing, and that provide QFs an opportunity to be paid for the full capacity costs they cause a utility to avoid. This Commission itself has recognized that the minimum contract term should account for the QF's financing needs and the value that QFs provide to ratepayers.

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 RMP's proposal, which limits renewable rates only to "like" resources. Further, all renewable QFs under Schedules 37 and 38 should have the option of being paid based on either a renewable or non-renewable avoided cost price, and the QF should keep the renewable energy certificates, unless the value of the power they are paid accounts for its renewable attributes.

RMP should accurately pay QFs for capacity by assuming that a reasonable percentage of QFs that enter into contracts actually get constructed. A 75% completion rate is a much-needed improvement; however, actual analysis of historical data could demonstrate a significantly lower rate.

Further, the Commission should reject RMP's proposals to:

- Limit standard prices to only the first 10 MWs of Schedule 37 contracts;
- Apply the Schedule 38 process and provisions to Schedule 37 QFs; and
- Apply the Proxy/PDDRR methodology used for Schedule 38 QF prices to Schedule 37.

Finally, RMP's tariffs should reflect that neither a state commission nor a utility can impose barriers to the formation of a legally enforceable obligation.

II. BACKGROUND

Congress enacted PURPA in 1978 to promote renewable energy, diversify the wholesale electric generation market, and to force monopoly utilities to purchase power from small and independent power producers.[1] Congress included mandatory purchase requirements because electric utilities are reluctant to purchase power from non-traditional facilities.[2] Under PURPA, the development of non-utility resources would be encouraged by removing structural barriers that prevented independent small power producers from selling electricity to utilities at reasonable prices.[3]

Much of PURPA's implementation has been delegated to FERC and the states.[4] Pursuant to this state delegation, the Commission implemented its current policy to give QFs the right to select long-term contracts of up to twenty years and allows them to negotiate even longer-term contracts.[5] Only three years ago, the Commission confirmed this policy and denied RMP's application to reduce QF contracts from 20 years to three years.[6]

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1 *FERC v. Am. Elec. Power Serv. Ass'n*, 461 U.S. 402, 404 (1983); *FERC v. Miss.*, 456 U.S. 742, 750-51 (1982)).

2 *Am. Elec. Power Serv. Ass'n*, 461 U.S. at 404-05.

3 *Swecker v. Midland Power Coop.*, 105 FERC ¶ 61,238, P 19 (2003).

4 16 U.S.C. § 824a-3(f).

5 *Re the Application of Rocky Mountain Power to Implement a Permanent Avoided Cost Methodology for Customers that Do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from QFs*, WPSC Docket No. 20000-388-EA-11, Record No. 12750 at 19 (Nov. 4, 2011).

6 *Re the Application of Rocky Mountain Power for the Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, WPSC Docket No. 20000-481-EA-15, Record No. 14220, Memorandum Opinion, Findings of Fact, Decision and Order at ¶ 25 (June 23, 2016).

On November 2, 2018, PacifiCorp, dba Rocky Mountain Power ("RMP"), filed a new request to shorten the Wyoming contract term, this time from twenty years to seven years. RMP has also proposed a number of changes to the calculation of avoided cost rates and the contract negotiation process, which in total will reduce the opportunity for non-utility generation owners to build new projects in Wyoming because they will impose illegal hurdles and obstacles to obtain contacts, and lower prices, especially for hydroelectric and solar generators.

III. ARGUMENT

A. The Commission Should Retain Twenty-Year Contract Terms

QFs have the right under FERC's rules and precedent to sell power under long-term contracts.[7] While FERC has never explicitly stated what the minimum acceptable contract length is, FERC recognizes that long-term contracts are necessary to ensure that QFs can sell under forecasted (rather than adjusted) rates, obtain financing necessary for construction and continued operation, and receive payment for capacity.[8] Therefore, short-term contracts without fixed prices violate FERC's rules, policies, and goals.

1. Long-Term Contracts Are Necessary to Pay QFs for the Capacity Value they Provide to a Utility

FERC's regulations provide a QF with the legal right to sell energy or capacity

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7 *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Pub. Util. Regulatory Policies Act of 1978*, FERC Order No. 69, 45 Fed. Reg. 12,214, 12,224 (Feb. 25, 1980); *Hydrodynamics Inc.*, 146 FERC ¶ 61,193 at PP. 33-34 (2014); *N.Y. State Elec. and Gas Corp.*, 71 FERC ¶ 61,027, 14-15 (1995).

8 FERC Order No. 69, 45 Fed. Reg. at 12,224; *Hydrodynamics Inc.*, 146 FERC at PP. 33-34; *N.Y. State Elec. and Gas Corp.*, 71 FERC at 14-15.

pursuant a legally enforceable obligation "over a specified term" with rates that are calculated at the time the obligation is incurred.[9] FERC has explained that this specified term includes the right to obtain long-term avoided cost rates.[10] QFs are entitled to a fixed contract so that a utility cannot circumvent the requirement that a QF be paid for capacity.[11] The need for QFs to be paid capacity should be a consideration for the Commission to determine how long of a contract term is "long" enough.

RMP's proposed seven-year contract terms will only allow QFs to be paid for a small portion of the capacity value they provide to the utilities and could result in QFs never being paid for the capacity. "The seven-year contract term, combined with RMP's pattern of 'committing' near-term resources and adding non-IRP resources, will effectively eliminate avoided capital costs from QF avoided cost rates."[12] PacifiCorp's current IRP shows that its next deferable resource for hydro and solar QFs will be acquired outside of the seven-year time horizon, thus these types of QFs will not be paid for capacity.

This period prior to PacifiCorp's next major resource acquisition is called the "sufficiency period." Any contract term that is equal to or shorter than this sufficiency period will mean that QFs will not be paid for any of the capacity costs that they will help defer. For example, if RMP's next planned resource acquisition is in 2027, its avoided cost schedule will include a deficiency period beginning on that date, meaning that RMP does

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9 18 C.F.R. § 292.304(d)(2)(ii); *N.Y. State Elec. & Gas Corp.*, 71 FERC at 14 .

10 *Hydrodynamics Inc.*, 146 FERC at P. 4, 8, 33.

11 *Id.* at P 33; *see also* FERC Order No. 69, 45 Fed. Reg. at 12,224.

12 Exhibit 600, REC 0056 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 55).

not pay for capacity for almost a decade.[13] Given that capacity payments are generally necessary for projects to be built, the practical impact of not paying for capacity is that projects will not be paid at all because they will never be constructed.

2. Contract Terms Should Allow Most QFs to Obtain Financing

This Commission and FERC have recognized that it is appropriate to consider project financing in determining the appropriate QF contract term, and the evidence in this proceeding demonstrates that seven-year contract terms will make it all but impossible for new QFs to develop. Any policy that effectively bars the vast majority of cost-effective QFs from being constructed is inherently inconsistent with PURPA, a law with the explicit purpose of encouraging the development of renewable and cogeneration resources.[14]

The Commission discussed that it is relevant to consider developer financing when setting the current twenty-year contract terms, and when recently confirming that policy. Specifically, the Commission recognized that parties advanced long-term contracts on the grounds that developers need to obtain project financing.[15] The Commission adopted twenty-year contract terms and rejected even longer-term contracts with the explanation that:

> The evidence presented in the instant case demonstrated wind QF facilities are being developed in Wyoming under PPAs with RMP having 20-year terms, which supports a finding that 20-year contract terms have

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13 *See* Exhibit 601, REC 0741 (John Lowe Direct Testimony at page 13).

14 *FERC v. Miss.,* 456 U.S. at 750-51 (noting PURPA's purpose is to diversify the supply of electric power by developing cost-effective non-utility resources).

15 *Re the Application of RMP to Implement a Permanent Avoided Cost Methodology for Customers that do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from QFs*, Docket No. 20000-388-EA-11, Record No. 12750 at 19 (Nov. 4, 2011).

been adequate for obtaining a QF project financing.[16]

In other words, the Commission adopted a policy based on a decision that the contract terms in that proceeding were adequate to allow QFs to receive sufficient financing and actually become constructed.

Further, the Commission recently refused to alter course on its decision to require twenty-year contracts.[17] In that case, RMP proposed to reduce the contract length from twenty years to three years.[18] RMP alleged that the reduction was warranted because "it [was] experiencing a large increase in QFs in the queue, which coupled with the long-term duration of the contracts, increases fixed price risks to Wyoming ratepayers."[19] The Commission found that RMP had not met its burden to show that a substantial reduction in the maximum term of its Wyoming contract would address the issue it alleges because "[t]he recent surge in QF applications [was] primarily occurring in other states."[20] Further, the Commission was concerned that RMP's proposal "risks discouraging QF development in Wyoming in contravention of PURPA, without any likely effect on whatever factors may be causing increased QF proposals in those other states."[21]

FERC has also stated long-term contracts are appropriate because QFs have a "need

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16 *Id.*

17 *Re the Application of Rocky Mountain Power for the Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, WPSC Docket No. 20000-481-EA-15, Record No. 14220, Memorandum Opinion, Findings of Fact , Decision and Order at ¶ 25 (June 23, 2016).

18 *Id.* at ¶ 26.

19 *Id.*

20 *Id.* at ¶ 96.

21 *Id.*

for certainty with regard to return on investment in new technologies."[22] In requiring long-term contracts, FERC recognized that long-term avoided cost rates would be inaccurate, but explained that this risk was less important than ensuring that QFs can obtain financing.[23] Therefore, the minimum contract term should be sufficient to allow both new and existing QFs an ability to obtain financing and continue to operate.

Both new and existing QFs need long-term contract terms with fixed prices to obtain financing.[24] Adequate financing is necessary for new projects to cover the initial upfront construction costs and meet debt requirements.[25] Unlike utilities, QFs are not guaranteed a rate of return on their investments, so they must rely on long-term contracts containing fixed contractual rights and prices that are not subject to changes over time.[26]

Further, even existing QFs need long-term contracts when they renew their contract. This is because existing projects often need to make system improvements, and this is especially true for QFs that are water systems, such as irrigation districts.[27] Trent Reed, General Manager for Shoshone Irrigation District also notes that twenty years is necessary for irrigation districts to facilitate long-term planning, system improvements, repairs and to meet or exceed environmental requirements.[28]. Sometimes even with long-term contracts, QFs need to have long-term financing that exceeds the contract term.[29]

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22 FERC Order No. 69, 45 Fed. Reg. 12,214 at 12,224.
23 *Id.*; *N.Y. State Elec. & Gas Corp.*, 71 FERC ¶ 61,027 at 14-15.
24 Exhibit 601, REC 0739 (John Lowe Direct Testimony at page 11).
25 *Id*.
26 *Id.*
27 *Id*; *See also* Exhibit 602
28 Exhibit 603, REC 0796 (Direct Testimony of Trent Reed at pages 3).
29 *Id.* at REC 0796-97 (Direct Testimony of Trent Reed at pages 3-4).

While shorter contracts may be sufficient for an operating irrigation district without a need for capital improvements, "[i]n most cases, capital improvements are going on continuously."[30] Therefore, the evidence in this case demonstrates, as in the Commission's case just three years ago, that short-term contract terms will at a minimum discourage QF development in Wyoming in contravention of PURPA and may effectively end PURPA development in Wyoming.

Short-term contracts have historically devastated QF development when they have been required. Washington's and Idaho's experiences tell compelling stories of the importance of contract terms, and how short-term contracts will make it nearly impossible for the vast majority of QFs to develop and operate.

PacifiCorp's standard contract rates in Washington are currently limited to five years.[31] PacifiCorp's overall company-wide operations have a small but important amount of QFs representing about 1,987 MW of installed capacity.[32] After over forty years since PURPA was passed, PacifiCorp is currently purchasing power from only **<u>three</u>** QF projects in Washington[33] with about 3 MWs total, which represents less than 0.002% of all of PacifiCorp's MWs from QF contracts.[34] Further, PacifiCorp currently has **<u>no</u>** new Washington QFs under contract.[35]

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30 *Id.* at REC 0797 (Direct Testimony of Trent Reed at page 4).
31 Exhibit 604, REC 0801 (RMP response to REC Data Request 1.13).
32 Exhibit 600, REC 0052 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 51).
33 Exhibit 601, REC 0740 (John Lowe Direct Testimony at page 12).
34 Exhibit 600, REC 0052 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 51).
35 *Id.*

Puget Sound Energy ("PSE") historically had ten-year contract terms and currently has 12-13 year contract terms, but has only twenty-four QF contracts, fifteen of which are 1 MW or less, with only two larger than 5 megawatts and a total QF nameplate capacity of around 60 MW.[36] Without analyzing the specific QF projects, PSE's experience shows that only a very small level of QF development is possible under ten to thirteen-year contracts.

Idaho's historic experience provides another cautionary tale. Idaho reduced contract terms to two years for wind and solar QFs, but kept twenty year terms for all other resource types.[37] Since that time, PacifiCorp has only entered into 3 QF contracts and is in negotiation with 2 others, all of which are for resources types other than wind and solar.[38] Currently, PacifiCorp has no new QFs under contract or in the pricing queue in Idaho.[39]

Finally, the Montana Public Service Commission was recently overturned on judicial review when it cut contract lengths from 25 years to 15 years.[40] In that case, the Montana District Court found that the Commission "lacked substantial evidence to determine that 15-year contracts are sufficiently '[l]ong-term … to enhance the economic feasibility of qualifying small power production facilities.'"[41] While the Montana contract

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36 Puget Sound Energy 2017 Integrated Resource Plan, Docket Nos. Dockets UE-160918 & UG- 160919, Appendix D Figure D-5 at D-15. (Available at: https://pse-irp.participate.online/).

37 Exhibit 601, REC 0740 (John Lowe Direct Testimony at page 12).

38 Exhibit 604, REC 0802 (RMP response to REC Data Request 1.14).

39 Exhibit 600, REC 0052 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 51).

40 Exhibit 315 & 515 at 6 (*Vote Solar et. al. v. Mont. Pub. Serv. Comm'n*, Cause No. BDV-17-0776 at ¶ 9 (Mont. 8th Jud. Dist. Ct.), *appeal pending*, No. DA 19-0223 (Mont. Super. Ct.)).

41 *Id.*

terms are implemented pursuant to a different state implementation, it is still relevant to the Wyoming Commission's stated desire to not discourage qualifying facilities.

PacifiCorp's own company-wide experience demonstrates that only a handful of QFs ever request seven-year contract terms. These are primarily cogeneration facilities that can use their electrical output for internal operations, may already have been operating, and do not rely upon only power sales to obtain financing.

Finally, the Commission should also maintain or expand long-term contracts because they are essential to project operations and development for reasons other than obtaining financing. Short-term contracts increase risks and costs, and provide RMP with another opportunity to raise obstacles to shut down existing projects. Short-term contracts also harm a QF's ability to make long-term plans that rely upon stable prices necessary for all aspects of operations. Long-term contracts are also necessary to allow QFs to remain economically viable because of the long resource sufficiency periods and low avoided cost rates.

The shorter-term (or no term) contracts cited by RMP undermine RMP's arguments. First, these are not comparable because they were either large projects developed in a deregulated market, like the no-contract Texas project, or had extenuating circumstances that explain how they were developed under short contract terms.[42] Further, only 1.5 percent of the contracts cited by RMP, even had contracts for terms of seven years

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[42] Exhibit 600, REC 0054-55 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 53-54).

or less.[43] The fact that such a small percentage of projects can be constructed with seven year terms even in radically different markets demonstrates that RMP's proposal does not pass the "straight face" test.

The evidence in this proceeding demonstrates that 20-year terms are already insufficient for many projects, especially irrigation district hydro facilities. Ted Sorenson, a 30-year veteran in developing, permitting, designing, and operating more than forty hydroelectric projects, notes that "a 20-year amortization is required to make these projects pencil."[44] However, there is only one operating hydro facility (the 0.20 MW City of Buffalo) selling power to RMP now,[45] despite Wyoming being a prime location for the development of new irrigation district hydro.[46] The Commission should instead be considering making improvements to Wyoming's PURPA market.

While shorter contracts may be sufficient for an operating irrigation district without a need for capital improvements, "[i]n most cases capital improvement projects are going on continuously."[47] Additionally, requiring irrigation districts to renegotiate their contracts every seven years would subject them to unnecessary costs, risks, harm, and even the re-opening of interconnection agreements resulting in "perpetual and wasteful negotiation that would ultimately harm [the irrigation districts'] end users who depend on reliable water

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43 *Id.* at REC 0055 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 54).

44 Exhibit 602, REC 0786 (Direct Testimony of Ted Sorenson at page 5).

45 Exhibit 604, REC 0811 (RMP response to REC Data Request 1.18, Attachment REC 1.18-1 at page 6).

46 Exhibit 602, REC 0784-86 (Direct Testimony of Ted Sorenson at page 3-5).

47 Exhibit 603, REC 0797 (Direct Testimony of Trent Reed at page 4).

service."[48]

In summary, the Commission should set the contract term at a length that ensures that most QF projects of all generation types can be financed. RMP has not presented evidence that anything more than a handful of projects will be able to be built or make capital upgrades with seven-year contracts. Indeed, the evidence demonstrates that most QFs cannot be built with five or even ten-year contracts. Seven-year (or other short-term) contracts in Wyoming will not stop QFs from selling power to RMP; however, it will cause those QFs to invest their capital in other states like Oregon and Utah in which they can obtain financing.

B. RMP Should Calculate Reasonable Avoided Cost Prices for All QF Resource Types On a "Like for Unlike" Basis

RMP's proposal only allows renewable QFs to be credited with avoiding the cost of a renewable resource if they are the same type RMP plans to acquire in its most recent IRP.[49] This means that a renewable QF with a resource not planned for in RMP's IRP would not be able to obtain a price that reflected its renewable attributes. For example, if RMP's Preferred Portfolio does not call for a new hydro or solar facility, these types of generation will not be eligible for renewable capacity payments. RMP proposes that "[i]f no renewable resources of the same type (as a QF) remain in the IRP preferred portfolio, the QF would be assumed to defer thermal resources, and avoided capacity costs would be based on the capital costs of the next deferrable thermal resource in the IRP preferred

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48 *Id*. at REC 0798 (Direct Testimony of Trent Reed at page 5).
49 Exhibit 3.0, 8 (Daniel McNeil Direct Testimony at page 7).

portfolio."[50] However, "[s]ince there are no thermal resources in the 2017 IRP Update preferred portfolio, baseload resources would be eligible to defer FOTs throughout their contract term."[51]

Contrary to RMP's proposal, any renewable QF should have its avoided cost pricing determined based upon its deferral of the next renewable resource, irrespective of type.[52] The PDDRR method simply compares the current IRP resource portfolio to the QF project seeking pricing to determine the portion of value created by adding the QF to the portfolio.[53] When RMP purchases renewable power from QFs, those QFs are allowing RMP to defer new renewable generation whether the QF matches the precise resource type PacifiCorp is planning to purchase or not.[54]

Limiting avoided cost prices by type also does not adequately compensate renewable QFs for their renewable power. This is because each renewable QF can defer RMP's energy and capacity needs associated with the earlier acquisition of a different type of renewable resources that PacifiCorp is planning to acquire.[55] The idea that a solar or hydro QF's power would not defer a future wind resource is not accurate and ignores the value of the renewable attributes.[56] Wyoming is an untapped market for the

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50 *Id.*
51 *Id*. at 10 (Daniel McNeil Direct Testimony at page 9).
52 Exhibit 601, REC 0743 (John Lowe Direct Testimony at page 15).
53 Exhibit 600, REC 0048 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 47).
54 Exhibit 601, REC 0732 (John Lowe Direct Testimony at page 4).
55 Exhibit 3.1, 9 (McNiel Rebuttal page 8) ("Q. Can a new resource defer resources of other types? A. Yes").
56 Exhibit 601, REC 0742-43 (John Lowe Direct Testimony at page 14-15).

development of small-scale hydroelectric projects, especially those on irrigation canals.[57] Those hydro projects will provide stable, non-intermittent, renewable energy, as well as capacity benefits to RMP.[58] Similarly, Wyoming is a prime location for the development of new solar generation.[59] It would be unreasonable to compensate them for only for the low prices of thermal and/or market prices, especially in an environment where RMP is actively seeking out other intermittent renewable resources.[60]

RMP maintains that unintended consequences and unreasonable results might occur without its "like for like" rule. RMP reasons that "[l]imiting deferral to QFs of the same type helps ensure reasonable alignment between the operating characteristics of a QF and the preferred portfolio resources it is assumed to defer, which in turn helps ensure that the least-cost, least-risk outcomes achieved by the preferred portfolio are maintained."[61]

There are no unreasonable consequences, however, because different renewable resources can simply be paid different capacity payments. Renewable resources of different types do not defer the same amount of capacity, and the PDDRR model can easily be adjusted to reflect the size of the deferred renewable resource to match the capacity contribution of a QF with a different renewable source. The PDDRR model also

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57 Exhibit 602, REC 0784 (Ted Sorenson Direct Testimony at page 3).
58 *Id.* at REC 0785&0789 (Ted Sorenson Direct Testimony at page 4&8).
59 Exhibit 604, REC 0812 (RMP response to REC Data Request 1.18, Attachment REC 1.18-1 at page 7).
60 *Id.*
61 Exhibit 3.0, 12 (Daniel McNeil Direct Testimony at page 11).

accounts for differences in operating characteristics between QF resources and deferred resources.[62]

Thus, when calculating avoided cost prices using the PDDRR methodology, the deferral of a renewable resource from the Preferred Portfolio should not be limited to resource type. Each QF type is deferring PacifiCorp's renewable need, and each QF's avoided cost prices should compensate PacifiCorp accordingly—including with appropriate adjustments for capacity equivalence. The total avoided costs include both capacity and energy, and should be evaluated as a combined price because the PDDRR's energy and capacity values should not be evaluated in isolation.

C. RMP Should Provide a Renewable Pricing Option So that QFs Can Select Between the Two Price Streams

All renewable QFs should have the option to select a renewable or non-renewable avoided cost price.[63] Under the renewable option, the QF would sell its net output and renewable energy certificates during the time when the avoided resource is based on a renewable resource, but retain the renewable energy certificates during any sufficiency period during which the prices are based on the market.[64] Under the non-renewable option, the QF would only sell its net output at an avoided cost price based on the next thermal resource and keep the renewable energy certificates.[65] The QF should be able to

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62 Exhibit 600, REC 0048 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 47) ("The PDDRR method can capture most of the cost impacts associated with different operating characteristics between a baseload resource and a wind resource.").

63 Exhibit 601, REC 0742 (John Lowe Direct Testimony at page 14).

64 Exhibit 600, REC 0049 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 48).

65 Exhibit 601, REC 0743-44 (John Lowe Direct Testimony at page 15-16).

compare renewable and non-renewable avoided cost pricing before selecting a price stream.[66]

A separate renewable price stream available to all renewable resources reflects the fact that renewable QFs can help utilities meet their state Renewable Portfolio Standards ("RPS") or to compensate utilities for the need to diversify their resource portfolio.[67] RMP argues that Wyoming does not have an RPS, so that a renewable rate is not necessary. RMP, however, acquires resources to meet its overall system needs, and any renewable QFs selling power to RMP purchases help RMP meet its RPS obligations in other states, just as RMP's owned Wyoming wind resources will.

RMP's proposal *requires* renewable resources that are the same resource type that PacifiCorp includes in its IRP to sell renewable power to PacifiCorp.[68] However, allowing QFs to choose might better reflect the value of the resource, and account for different business models including that some QFs may already have sold their RECs or need to keep them for financing.[69] Therefore, it is reasonable to have both a renewable and non-renewable price stream with the QF option to select.

RMP also argues that allowing the QF to keep renewable energy certificates would harm ratepayers because, under current policy, RMP and not the QF keeps the renewable energy certificates.[70] It makes sense to allow the QF to keep the renewable energy certificates when the calculation of avoided costs is based on the costs of market

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66 *Id.* at REC 0743 (John Lowe Direct Testimony at page 15).
67 *Id.* at REC 0742-43 (John Lowe Direct Testimony at page 14-15).
68 Exhibit 3.0, 8 (Daniel McNeil Direct Testimony at page 7).
69 Exhibit 601, REC 0744 (John Lowe Direct Testimony at page 16).
70 Exhibit 3.1, 18 (Daniel McNeil Rebuttal Testimony at page 17).

purchases and/or a natural gas-fired plant that does not produce associated green attributes. But for purchasing power from the QF, RMP would build a generation resource that did not have green attributes, and RMP should not be provided something that would not be associated with its avoided resource.

D. RMP Does Not Fully Compensate QFs for Avoided Capacity

RMP does not fully compensate QFs for capacity in the sufficiency period.[71] QFs defer front office transactions in more months than RMP claims, and RMP undervalues the long-term avoided capacity value of a QF.[72] Because RMP experiences capacity deficits in more months than simply the months containing its peak-loads, RMP should be paying QFs for the capacity value they provide in all months for which there is a deficit.[73] Further, RMP fails to account for the long-term security in price and availability that QFs provide by assuming that a large quantity of front office transactions will be available.[74] Because those front office transactions may not be available or may only be available at high costs, RMP is undervaluing the capacity value of QFs.[75]

A more reasonable approach would be to use a Single-Cycle Combustion Turbine ("SCCT") to value capacity because the Northwest is already capacity deficient.[76] This is

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71 Exhibit 600, REC 0040 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 39).

72 *Id*.

73 *Id.* at REC 0040-41 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 39-40).

74 *Id.* at REC 0041 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 40).

75 *Id.* at REC 0041-42 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 40-41).

76 *Id.* at REC 0042 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 41).

an approach the RMP has previously used in Wyoming.[77] Further, recently the Washington Utilities and Transportation Commission adopted a new rule requiring that utilities base capacity on a peaking unit.[78]

Additionally, the Commission should reject RMP's proposal to assume that 100% of QFs that enter into contracts will actually be constructed. This assumption is entirely unreasonable and without any basis in history or otherwise. This assumption would lower RMP's avoided cost rate artificially. A more reasonable position would be to use the historic percentage of QFs that are constructed, compared to the entire queue or certain completion milestones that show a project is more likely to be constructed—like completing the interconnection study process or executed contracts or both. The 75% completion rate previously approved by the Commission is reasonable,[79] however, it appears to be on the high end of what is reasonable.[80] Actual analysis of historical data could demonstrate a significantly lower rate, but the 100% completion rate assumption is entirely unfounded.[81] As such, the Commission should not permit RMP to use a 100% completion rate, but should instead use 75%, or direct RMP to formulate a reasonable completion rate based on historical data.

E. Schedule 37 Size Cap

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77 *Id*. at REC 0043 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 42).

78 *In re Amending, Adopting, and Repealing Sections of WAC 480-106 and 480-107*, WUTC Docket No. U-161024, General Order No. R-597 (June 12, 2019) (WAC 480-106-040).

79 Exhibit 600, REC 0066 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 65).

80 Exhibit 601, REC 0749 (John Lowe Direct Testimony at page 21).

81 *Id.* at REC 0733 (John Lowe Direct Testimony at page 5).

The Schedule 37 restriction limiting standard prices to only the first 10 MW of system resources should be eliminated. RMP proposes that once it enters into 10 MWs of Schedule 37 contracts, then all other QFs above 100 kW would need to negotiate their rates. Further, the 10 MW trigger is inconsistent with the way Schedule 37 rates are calculated using 50 MW of incremental capacity.[82] It would mean that QF resources will never actually reach the 50 MW modeled.[83] This cap should therefore be eliminated, or in the alternative increased to 100 MW because no project as small as 100 kw should have to be exposed to non-standard prices and contracts.[84] It would also be appropriate for the Commission to eliminate the 10 MW but allow RMP to file an update once the 10 MW is reached.[85]

F. Schedule 38 Contract Provisions and Processes are Not Appropriate for Small 37

RMP proposes that the Schedule 38 negotiation process apply to Schedule 37 QFs. This proposal should be rejected for a number of reasons. First, small QF contracts are far more streamlined, simple to negotiate, and prices are published.[86] There is no need for any negotiation over the main substantive term, the price, and any other terms have generally been standardized.[87]

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[82] Exhibit 600, REC 0068 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 67).

[83] *Id.* at REC 0069 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 68).

[84] Exhibit 601, REC 0733 (John Lowe Direct Testimony at page 5); Exhibit 600, REC 0069 (Dr. Marc Hellman and Dr. Lance Kaufman Direct Testimony at page 68).

[85] Exhibit 300/500, 40 (Dr. Kevin C. Higgins Direct Testimony at page 38).

[86] Exhibit 601, REC 0751 (John Lowe Direct Testimony at page 23).

[87] *Id.*

PacifiCorp's Oregon version of Schedule 37 includes an appropriate process for negotiations with small QFs that includes informational requirements and timelines.[88] In Oregon, PacifiCorp can enter into Schedule 37 PPAs much more quickly because they are streamlined and simple. Therefore, a simple process like that in Oregon should be adopted for RMP's Wyoming Schedule 37.

Second, a small QF should not have to look in Schedule 38 to discern the contract negotiation process because they are small and relatively unsophisticated. RMP's proposal would require these projects to hunt and peck through the utility's tariff in order to figure out what provisions of Schedule 38 apply, when some specifically do not apply. For example, Schedule 38 references indicative prices, which makes no sense to a small QF because Schedule 37 prices are fixed. Additionally, Schedule 38 requires that certain information be given to get indicative prices and then more information to get the PPA. This also does not make any sense for a small QF because Schedule 37 already has prices, and there is no need for two steps. Therefore, by requiring small QFs to look to both RMP's Schedule 37 and Schedule 38 for contract provisions and process, the Commission would create an unnecessarily confusing environment for relatively unsophisticated QFs, and may even result in litigation where QFs and RMP dispute conflicting language in the two schedules. As such, the Commission should reject RMP's request to apply the Schedule 38 process and contract provisions to Schedule 37 QFs and should approve less onerous and more expedited processes for entering into Schedule 37 contracts.

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[88] *Id.*

G. RMP's Proposed Limitations on Execution of a Contract Violate FERC's Rules on Legally Enforceable Obligations

RMP has proposed that contract price and terms will not be effective until after it executes the PPA and the Commission approves it, and RMP has proposed that it can refuse to provide an executable PPA if RMP decides or otherwise does not provide a final transmission agreement. FERC does not allow a utility or state commission to impose these types of limitations on a QF's ability to obtain a contract or otherwise "lock in" avoided cost rates, and the Commission should require RMP to remove these restrictions from its proposed Schedule 37 and 38.

1. FERC's LEO Standards Allow a QF to Obtain the Prices at the Time the QF Obligates Itself to the Utility and Not When the Utility Decides to Provide a Transmission Agreement or Execute a PPA

Federal law allows a QF to determine the date upon which the QF commits itself to sell its energy and capacity to the utility and to "lock in" the then-current avoided cost rates. At its core, a QF has the power to determine the date for which avoided costs are calculated by simply tendering an agreement that obligates it to provide power. Neither a utility nor a state commission can impose restrictions or processes that have the practical effect of delaying the contract negotiation process so that a later and lower avoided cost is applicable.

The LEO concept is intended to give the QF control over when the utility becomes obligated to purchase the QF's output.[89] The utility's obligation to purchase QF

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89 *Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187 at P.36 (2013); *Re Commission Investigation into QF Contracting and Pricing*, Docket No. UM 1610, Order No. 16-174 at 23 (May 13, 2016) (noting that the purpose of a LEO

power is created by statutes, regulations and administrative rules and may be triggered by the QF's self-imposed obligation to deliver energy. Federal statutes, regulations and administrative rules govern the utility's obligation to purchase power. Under PURPA, state regulatory agencies are required to implement the rules adopted by FERC.[90]

FERC's rules provide that each QF shall have the option to provide energy or capacity pursuant to a contract or other LEO over a specified term at avoided costs that are either calculated at the time of delivery or at the time the obligation is incurred.[91] Oregon law also specifically contemplates that a QF has the right to a price based on the "projected avoided costs calculated at the time the legal obligation to purchase the energy or energy and capacity is incurred."[92] FERC's intention in adopting its rules was explicit: "[u]se of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility."[93]

States have the initial power to determine the specific parameters of when a LEO is formed;[94] however, any state requirement that is inconsistent with federal law and regulations is invalid.[95] For example, a state rule or policy requiring, per se, that a PPA be executed by one or both parties in order to form a LEO is invalid because it is

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is to "[prevent] a utility from circumventing PURPA requirements by refusing to execute a contract").

90 PURPA § 210; 16 USC § 824a-3.

91 18 CFR 292.304(d).

92 ORS 758.525(2)(b).

93 45 Fed. Reg. 12214, 12224 (Feb. 25, 1980).

94 *West Penn Power Co.*, 71 FERC ¶ 61,153 at 61,495 (1995).

95 *See Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 at P.35 (2011).

inconsistent with PURPA and FERC's regulations.[96] In a series of cases in Idaho, FERC found that it was inconsistent with PURPA and FERC's regulations for the Idaho commission to require that a PPA be executed by one or both parties in order to form a LEO prior to a regulatory change.[97] All of those cases were affected by a December 14, 2010 change in the eligibility requirements for published avoided costs that the Idaho commission determined made each QF ineligible for those published avoided costs.[98] In *Cedar Creek*,[99] *Rainbow Ranch*,[100] and *Murphy Flat*,[101] the QF executed the PPA prior to that December 14 eligibility change but the utility executed it on or after that date. In *Grouse Creek*, neither the QF nor the utility executed the PPA prior to December 14; however, the *Grouse Creek* QF provided final site-specific information by December 9, signed the agreement on December 20, and the utility signed on December 28.[102] The Idaho commission rejected the executed PPAs in each of these cases because they were either not executed by one or both parties prior to the eligibility rule change.[103] FERC found that in all four instances the QFs:

> had engaged in formal negotiations to enter into power purchase agreements with electric utilities during November and December 2010, and all four QF petitioners had unequivocally committed themselves to sell to the utilities

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[96] *See id.*; *see also Grouse Creek, LLC*, 142 FERC ¶ 61,187 at PP. 37-38 (2013).

[97] *See Cedar Creek*,137 FERC ¶ 61,006 at P.30, *Rainbow Ranch Wind, LLC*, 139 FERC ¶ 61,077 at P.23 (2012), *Murphy Flat Power, LLC*, 141 FERC ¶ 61,145 at P.25 (2012), and *Grouse Creek*,142 FERC ¶ 61,187 at P.36.

[98] *See Grouse Creek*, 142 FERC ¶ 61,187 at PP.2-4 & 7-9.

[99] *Cedar Creek*, 137 FERC ¶ 61,006 at P.8.

[100] *Rainbow Ranch*, 139 FERC ¶ 61,077 at P.11.

[101] *Murphy Flat*, 141 FERC ¶ 61,145 at P.6.

[102] *Grouse Creek*, 142 FERC ¶ 61,187 at PP.6 & 14.

[103] *See id.* at PP.6-9.

> prior to the new rules concerning eligibility for published avoided cost rates went [*sic*] into effect, i.e., before December 14, 2010.[104]

FERC reasoned that, because the purpose of a LEO was to prevent utilities from refusing to sign contracts or delaying signing until a lower rate was in effect, the Idaho commission's requirement that the contract be executed to form a LEO was inconsistent with PURPA and FERC's regulations implementing PURPA.[105] Therefore, a state commission rule requiring contract execution to form a LEO is invalid as a matter of law. Instead, where a contract has not been executed prior to a rule change, a LEO can, at a minimum, still be created where negotiations took place, the material terms were finalized, and the QF unequivocally committed to sell to the utility prior to the rule change.

Further, a state rule that requires, per se, that certain procedural steps be completed prior to LEO formation is also invalid as inconsistent with PURPA and FERC regulations.[106] This is especially true when those steps are under the control of or provide discretion to the utility regarding when a contract is entered into. FERC found that it was inconsistent with PURPA and FERC's regulations for the Montana commission to require that an interconnection agreement be tendered to the utility in order to form a LEO prior to a regulatory change.[107] In *FLS Energy*, the QF tendered its executed PPA to the utility prior to a June 16, 2016 change in the eligibility requirements for standard rates but had not tendered its interconnection agreement because the utility had not provided

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[104] *Id.* at P.37.
[105] *Id.* at P.36.
[106] *See FLS Energy, Inc.*, 157 FERC ¶ 61,211 at P.23 (2016).
[107] *Id.*

an executable copy of the interconnection agreement.[108] FERC reasoned that, because "the establishment of a [LEO] turns on the QF's commitment, and *not* the utility's actions,"[109] the Montana commission's requirement that an interconnection agreement be tendered was inconsistent with PURPA and FERC's regulations.[110] This would inappropriately allow a utility to "control whether and when a [LEO] exists—e.g. by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement."[111] Therefore, a state commission rule requiring certain procedural steps that are within the utility's control and over which the utility has the power to delay, is invalid as a matter of law. Instead, where those procedural steps have not been completed prior to a rule change, a LEO can still be created by looking at the facts and circumstances of the case.

2. RMP's Schedule 37 and 38 Violate FERC's LEO Requirements

RMP's proposes to include language in Schedule 37 that limits the price to when RMP decides to execute a PPA and/or provides an interconnection agreement. Schedule 37 states that prices available to the QF are 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 …." Schedule 38 has even broader limitations allowing RMP to not execute a PPA until the "simultaneous execution of an interconnection agreement between the QF Owner and the [RMP]" and that prices "are not final and binding until

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108 *Id.* at PP.3-4.
109 *Id.* at P.24.
110 *Id.* at PP.23-26.
111 *Id.* at P.23.

the power purchase agreement is executed by both parties and accepted for filing by the Wyoming Public Service Commission."

As explained by Mr. Lowe:

> 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.[112]

This has important practical ramifications for QFs. Rocky Mountain Power, can impose roadblocks or obstacles on QFs seeking to obtain a contract, including but not limited to imposing barriers to starting the contract process, and delaying negotiations so a contract cannot be obtained before a price reduction and lower prices becoming effective. [113]

Based on his decades working for PacifiCorp, and then as the Executive Director of REC, Mr. Lowe proposed a number of guidelines that the Commission should consider when adopting standards regarding when a QF can obtain a LEO, including the providing of necessary information and committing to sell their power to the utility.[114] Specifically, Mr. Lowe recommended that

> A QF should be allowed to create a legally enforceable obligation if the QF is unable to resolve outstanding issues after providing 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

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112 Exhibit 601, REC 0760 (John Lowe Direct Testimony at pages 32).
113 Exhibit 601, REC 0760-62 (John Lowe Direct Testimony at pages 32-34).
114 Exhibit 601, REC 0760-65 (John Lowe Direct Testimony at pages 32-37).

> 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. [115]

This will allow a QF to create a legally enforceable obligation by committing itself to sell power under the then current rates if there are unresolved disputes after RMP has provided (or should have provided) a draft contract. Mr. Lowe's approach protects utilities from last-minute efforts of QFs attempting to lock into prices before they change. For example, QFs should not be able to form a LEO until they have provided information, received a draft contract and requests for additional information (assuming the utility timely provides a draft PPA as sometimes utilities simply refuse to provide draft PPAs), and the QF has attempted to resolve the outstanding issues.

If the Commission does not adopt these specific polices, then at a minimum it should remove the language in Schedule 37 and 38 that imposes unreasonable restrictions on the contracting process.

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115 Exhibit 601, REC 0763-64 (John Lowe Direct Testimony at pages 35-36).

H. The Commission Should Retain the Current Schedule 37 Price Calculation Methodology

Rocky Mountain Power has proposed to change the Schedule 37 pricing methodology from the currently used Grid/Proxy methodology to the Proxy/PDDRR methodology, which is used for Schedule 38 QF prices. The practical impacts of this would be a complex rate setting process (which will increase work on the Commission and intervenors to review the accuracy of the pricing) and lower the prices. This change is a representative example of RMP attempting to propose changes which are unnecessary and simply make the current difficult environment for small QFs in Wyoming even more challenging. Schedule 37's prices are already too low to allow for the development of small-scale projects, and fail to fully compensate QFs for their full capacity and energy value. Rocky Mountain Power's proposal would further exacerbate this problem and result in challenges to and less transparency in the determination of contracted prices.[116]

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. Schedule 37 was recently changed to allow all 5 MW and lower hydro projects to be eligible, and the recent improvements in eligibility could be effectively eliminated with a switch to Schedule 38.

There are very few Schedule 37 projects in Wyoming at this point, with only three

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[116] Exhibit 601, REC 0734, 0751 (John Lowe Direct Testimony at pages 6, 23).

projects for a total of 0.40 MWs.[117] Given that Wyoming already has 20-year contract terms and natural resources for renewable energy, the primary explanation for the dearth of Wyoming small scale QFs are low prices for Schedule 37.

RMP argues that the switch should be made because it is more accurate and results in higher prices for baseload hydro projects (but lower prices for wind, fixed solar and tracking solar). RMP confuses precision for accuracy. Schedule 38's complex process produces more specific and detailed prices, but they are not necessarily more accurate. REC is resource agnostic, and if a methodology increases prices for hydro but decreases them for wind and solar, then it is not a solid basis to adopt a change. More important, REC is involved in litigating avoided cost methodologies that are used in all of PacifiCorp's states, and price changes are based both the pricing methodology as well as the specific inputs and assumptions. The results RMP shows in this case may not be illustrative of pricing that will occur in the future. REC believes that using Schedule 38 will generally result in lower prices for all resource types.

IV. CONCLUSION

For the reasons explained herein, REC urges the Commission to retain twenty-year contract terms to ensure that most Wyoming QFs can obtain necessary financing for development and equipment upgrades, and to offset periods of low prices during early contract years. The Commission should also reject RMP's "like for like" proposal and direct RMP to provide a renewable pricing option. Finally, the Commission should

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117 Exhibit 604, REC 0811-12 (RMP response to REC Data Request 1.18, Attachment REC 1.18-1 at page 6-7).

require RMP to accurately price QF capacity and reject RMP's proposals to apply Schedule 38 processes and prices to Schedule 37 projects.

Dated this 8th day of August 2019.

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CERTIFICATE OF SERVICE

I hereby certify that on this 8th day of August 2019, the **BRIEF 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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