BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

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

NON-CONFIDENTIAL

DIRECT TESTIMONY

AND EXHIBIT

OF

KEVIN C. HIGGINS

On Behalf of

Wyoming Industrial Energy Consumers

and

Two Rivers Wind, LLC

April 19, 2019

WIEC Exhibit No. 300
Two Rivers Wind Exhibit No. 500

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by the Wyoming Industrial Energy Consumers ("WIEC") and Two Rivers Wind, LLC ("Two Rivers Wind").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy.

From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE WYOMING PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. While this is my first time testifying on Two Rivers Wind's behalf, I have testified on WIEC's behalf numerous times. I recently testified in the case addressing the application by Rocky Mountain Power ("RMP" or the "Company") for a certificate of public convenience and necessity ("CPCN") for the replacement of its Foote Creek I wind facilities. I have also testified in the last seven RMP general rate case proceedings: Docket Nos. 20000-469-ER-15, 20000-446-ER-14, 20000-405-ER-11, 20000-384-ER-10, 20000-352-ER-09, 20000-333-ER-08, and 20000-277-ER-07.

In 2017, I testified in the case addressing RMP's application for CPCNs and nontraditional ratemaking for wind and transmission facilities, Docket No. 20000-520-EA-17; RMP's Bonus Tax Depreciation case, Docket No. 20000-506-EA-16; and RMP's Demand-Side Management ("DSM") proceeding, Docket No. 20000-502-EA-16.

I also testified in RMP's previous Qualifying Facilities ("QF") proceeding, Docket No. 20000-481-EA-15 (2016); RMP's Deer Creek Mine proceeding, Docket No. 20000-464-EA-14 (2015); RMP's depreciation proceeding, Docket No. 20000-427-EA-13 (2013); RMP's 2013 Energy Cost Adjustment Mechanism

("ECAM") proceeding, Docket No. 20000-432-EA-13 (2013); RMP's DSM proceeding, Docket No. 20000-383-ER-10 (2011); RMP's 2011 avoided cost proceeding, Docket No. 20000-388-EA-11 (2011); RMP's 2010 ECAM proceeding, Docket No. 20000-368-EA-10 (2010); and RMP's 2009 avoided cost proceeding, Docket No. 20000-342-EA-09 (2009).

I also testified in the Powder River Energy Corporation ("PRECorp") security deposit case, Docket No. 10014-175-CT-16, the PRECorp cost of power adjustment case, Docket No. 10014-172-CP-16, and the last two PRECorp general rate cases, Docket No. 10014-168-CR-16 and Docket No. 10014-145-CR-13.

Finally, in 1996, I filed testimony in Docket No. 20000-ER-95-99, in which RMP's predecessor, PacifiCorp d/b/a Pacific Power & Light Company, requested approval of an alternative form of regulation plan.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE ANY OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have testified in approximately 220 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, and West Virginia. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission ("FERC") and prepared expert reports in state and federal court proceedings involving utility matters.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE?

A. My direct testimony responds to various proposals by RMP to change the terms under which the Company purchases power from QFs, including a reduction in the maximum standard term for fixed price power purchase agreements ("PPAs") for QFs from twenty years to seven years; proposed modifications to the Company's avoided cost methodology used for tariff Schedules 37 and 38; and certain other changes to tariff Schedules 37 and 38.

Q. PLEASE PROVIDE A SUMMARY OF YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS.

A. I offer the following conclusions and recommendations:

1. RMP's proposal to reduce the maximum standard term for fixed price contracts for QFs from twenty years to seven years is neither reasonable nor in the public interest and should be rejected by the Commission.
2. RMP is proposing a modification to its avoided cost calculation that would determine the applicable proxy resource in that calculation to be the next deferrable resource *of the same type* as the QF in the Company's preferred portfolio in its Integrated Resource Plan ("IRP").[1] In circumstances in which the next deferrable resources for wind and solar QFs occur relatively

[1] This proposal is sometimes referred to as the "like for like" proposal.

close in time, such as within two years of each other, I agree that it would be reasonable to use this convention to calculate the avoided costs for wind and solar QFs. However, if the timing of the next deferrable wind and solar resources begins to diverge substantially, i.e., beyond two years, the Commission should retain reasonable flexibility to allow the Company's proposed "like for like" convention to be waived and to permit wind and solar QFs to obtain avoided cost pricing based on the next deferrable renewable resource, irrespective of QF type, on a capacity-equivalent basis.

3. Further, cogeneration QFs should be eligible for deferring the Company's planned investment in geothermal resources, since cogeneration and geothermal are both baseload resources. And although I am not recommending that the Commission reject the "like for like" convention for determining the avoided cost of cogeneration QFs, I believe the Commission should also show flexibility in the future if a cogeneration QF can reasonably make the case that its project defers the need for new RMP solar or wind in the IRP, and potentially to allow the determination of avoided cost on that basis.

4. I do not object to RMP's proposal to calculate Schedule 37 avoided costs using the same method employed for Schedule 38, as I believe it is reasonable to calculate Schedule 37 and Schedule 38 avoided costs on a consistent basis.

5. I also do not object to RMP's proposal to change the on-peak and off-peak

definitions used in making payments to QFs. The change is intended to improve price signals for payments to QFs without changing the total expected avoided cost payments to a QF as currently calculated for Schedule 38. It is thus an attempt to fine tune actual payment to better correspond to market value by hour.

6. A number of RMP's proposed tariff changes are either unnecessary or else harmful to the public interest in that the proposed changes unreasonably shift the PPA negotiation leverage to RMP's advantage. In particular:
   a. It is unnecessary to adopt RMP's proposed language for Schedules 37 and 38 stating that "providing a pro-forma PPA does not mean the QF is at the PPA negotiation phase."
   b. RMP should not be granted a unilateral and open-ended ability to update PPA pricing *any time* prior to contract execution. Such broad discretion for the Company is unreasonable and potentially subject to abuse. The current standard, which permits RMP to update pricing proposals at appropriate intervals, should be maintained.
   c. Rather than adopt RMP's proposal to require Schedule 37 customers to seek Schedule 38 pricing once the 10 MW cap on Schedule 37 pricing is reached, the 10 MW cap should simply be eliminated. RMP already plans to reset Schedule 37 rates annually, and if the cap is reached before that occurs, the Company should be free to update Schedule 37 rates at that time.

II. BACKGROUND

Q. PLEASE PROVIDE A BRIEF BACKGROUND OF THIS PROCEEDING.

A. On November 2, 2018, RMP filed an application with the Commission requesting approval to reduce from twenty years to seven years the maximum contract term for prospective PPAs with QFs under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA was enacted to encourage the development of QFs, which are cogeneration facilities meeting certain efficiency criteria and small renewable power production facilities. In fact, PURPA directs the FERC, in consultation with state regulatory authorities, to promulgate rules to carry out this goal. Additionally, my understanding is that, when enacting PURPA, Congress recognized the specific issue that public utilities, such as RMP, were reluctant to purchase power from, and to sell power to, these nontraditional facilities. To overcome this reluctance, PURPA requires RMP to purchase QF power under the so-called "must purchase" or "must take" obligation.

In addition to RMP's request to reduce the QF contract term length from twenty years to seven years in this proceeding, the Company is also seeking approval of certain modifications to its avoided cost methodology used for tariff Schedule 37 "Avoided Cost Purchases from Qualifying Facilities" and tariff Schedule 38 "Avoided Cost Purchases from Non-Standard Qualifying Facilities," as well as certain other changes to those tariff schedules. RMP's proposals are described in the direct testimony of Company witnesses Daniel J. MacNeil and Mark P. Tourangeau.

This proceeding, though, should not be viewed in isolation. Nearly four years ago, on August 26, 2015, RMP filed an application in Docket No. 20000-481-EA-15. In that proceeding, RMP proposed to reduce from twenty years to three years the maximum contract term for PPAs with QFs. The Commission rejected this proposal, concluding that RMP "failed to meet its burden to demonstrate that the proposed modification of the Wyoming PPA contracts is reasonable, will solve an alleged system-wide problem, and is in the public interest of Wyoming ratepayers."[2] Instead, the Commissioned directed RMP "to initiate a collaborative process with relevant stakeholders to address substantive and procedural reforms to Wyoming's PPA process and [partial displacement differential revenue requirement] avoided cost methodology."[3]

Q. DID YOU PARTICIPATE IN DOCKET NO. 20000-481-EA-15?

A. Yes. I testified on behalf of WIEC, the Rocky Mountain Coalition for Renewable Energy, and Chevron Power and Energy Management Company. In that case I recommended the Commission reject RMP's proposals to reduce the maximum standard term for fixed price PPAs for QFs from twenty years to three years and to include proposed QFs without executed contracts in the avoided cost calculation for new Wyoming QFs.

[2] Docket No. 20000-481-EA-15, Memorandum Opinion, Finding of Facts, Decision and Order (June 23, 2016) at paragraph 25.
[3] *Id.*

Q. DID YOU PARTICIPATE IN THE COLLABORATIVE PROCESS ESTABLISHED PURSUANT TO DOCKET NO. 20000-481-EA-15?

A. I did not personally participate in the collaborative, although WIEC did. In his direct testimony, Mr. Tourangeau reports that all of the Company's recommendations for changes to Schedule 38 were rejected.[4] But based on discovery responses in this proceeding, RMP has admitted that its recommendations in the collaborative process followed closely with its testimony as filed in Docket No. 2000-481-EA-15.[5] As a result, I am not surprised that the parties involved in the collaborative process rejected RMP's recycled proposals.

Q. WHAT WAS THE BASIS FOR THE COMPANY'S REQUEST TO REDUCE THE MAXIMUM STANDARD TERM FOR QFS FROM TWENTY TO THREE YEARS IN DOCKET NO. 20000-481-EA-15?

A. Among the reasons cited, the Company cautioned against a predicted rise in QF contract executions and pricing requests. Specifically, in the Company's 2015 filing in Docket No. 20000-481-EA-15, RMP witness Paul H. Clements warned of a dramatic increase in QF contract executions and pricing requests[6] and testified that "The Company currently has 403 megawatts ("MW") of existing PURPA contracts in Wyoming (projects that are either online or projects that have executed contracts with future online dates) and 713 MW of proposed PURPA contracts in Wyoming (projects that have requested pricing but do not yet have executed

[4] Direct Testimony of Mark P. Tourangeau, p. 30.
[5] *See* RMP Response to WIEC-VK-TR 4.17, which is included in WIEC Exhibit No. 300.1/Two Rivers Wind Exhibit No. 500.1.
[6] Docket No. 20000-481-EA-15, Direct Testimony of Paul H. Clements, p. 11.

contracts), together totaling 1,116 MW of nameplate capacity."[7]

Q. SINCE THE COMMISSION REJECTED RMP'S LAST ATTEMPT TO REDUCE THE MAXIMUM PPA TERM FOR QFS IN 2016, HAS WYOMING SEEN A DRAMATIC INCREASE IN QF POWER COMING ON LINE AS THE COMPANY WARNED?

A. No. In 2013, two years before RMP's 2015 filing, there were approximately 281 MW of QF power on line in Wyoming.[8] By 2014, this amount dropped to approximately 190 MW.[9] According to Mr. Tourangeau's testimony in this proceeding, today there are 398 MW.[10] An increase of 208 MW over a five-year period is hardly the deluge that RMP predicted. And of the 713 MW of proposed QF contracts that Mr. Clements referenced in the 2015 case, only 80 MW have come into service, 560 MW are in progress but not in service, and 73 MW have been deactivated.[11]

In contrast, as I explain in more detail below, RMP has obtained approval to repower or acquire nearly 1,900 MW of Company-owned wind generation in Wyoming *in the last year alone*. This includes 950 MW of new Wyoming wind in Docket No. 20000-520-EA-17[12] and 594 MW of repowered Wyoming wind in

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[7] *Id.*, p. 2.
[8] Based on Docket No. 20000-481-EA-15, RMP's Responses to WIEC 1.2, Attach WIEC 1.2, and WIEC 1.4, Attach WIEC 1.4, which are included in WIEC Exhibit No. 300.1/Two Rivers Wind Exhibit No. 500.1.
[9] Based on Docket No. 20000-481-EA-15, RMP's Responses to WIEC 1.3, Attach WIEC 1.3, and WIEC 1.5, Attach WIEC 1.5, which are included in WIEC Exhibit No. 300.1/Two Rivers Wind Exhibit No. 500.1.
[10] Direct Testimony of Mark Tourangeau, Table 1, p. 7.
[11] RMP Response to WIEC-VK-TR Data Request 2.1, which is included in WIEC Exhibit No. 300.1/Two Rivers Wind Exhibit No. 500.1.
[12] In Docket No. 20000-520-EA-17, an additional 200 MW of new Wyoming wind was approved to be acquired through a PPA with the Cedar Springs project.

Docket No. 20000-519-EA-17.[13] I point this out not because I am contesting any of the approvals obtained, but merely to provide some perspective regarding the relative magnitudes of QF generation compared to RMP's planned investment in renewable power.

Q. MR. TOURANGEAU HAS IDENTIFIED 1,518 MW OF WYOMING QF GENERATION IN THE "PRICING QUEUE." DO YOU HAVE ANY OBSERVATIONS ABOUT THE POTENTIAL IMPACT OF THOSE PROJECTS?

A. Yes. It may be years before many of these projects come online, if they even come online at all. As I pointed out above in reference to Docket No. 20000-481-EA-15, not all proposed QF projects get developed. Further, I understand that the turnaround time on interconnection studies performed by the Company has become increasingly drawn out. Prior to signing a PPA, a QF must complete milestones toward obtaining an interconnection agreement. One of the milestones is a system impact study, which is performed by the Company. According to the Company's tariff, RMP is supposed to use reasonable efforts to complete a system impact study within 90 days. However, my understanding is that PacifiCorp's system impact studies are now taking approximately two years to complete, and sometimes even longer if a restudy is required.[14] Moreover, following the system impact study, a

[13] Projected total Company capacity from repowered projects approved in Docket No. 20000-519-EA-17 is approximately 922 MW. *See* Docket No. 20000-519-EA-17, Redacted Exhibit RMP__(RTL-1SD).

[14] WIEC and Two Rivers Wind have outstanding discovery requests, which are subject to a Motion to Compel, regarding the timing of these studies. As a result, I reserve the right to update this portion of my testimony based on the Motion to Compel and any discovery responses obtained.

facilities study must be completed. Thus, while it is not possible for me (or RMP) to predict with certainty how much of the 1,518 MW of Wyoming QFs identified by Mr. Tourangeau will come online, it is unlikely that all of the projects will do so – and the ones that do come online must contend with the impact on their commercial operation dates of the Company's lengthy interconnection study process.[15]

III. RESPONSE TO RMP'S PROPOSED CHANGES

Q. BRIEFLY DESCRIBE THE CHANGES BEING PROPOSED BY RMP.

A. The Company's proposed changes fall into three basic categories:

(1) A proposed change to the maximum standard term for fixed price PPAs for QFs;

(2) Proposed modifications to its avoided cost methodology used for tariff Schedules 37 and 38; and

(3) Certain other changes to tariff Schedules 37 and 38.

I will discuss each in turn.

Maximum standard term for fixed price PPAs

Q. WHAT IS RMP PROPOSING REGARDING THE MAXIMUM STANDARD TERM FOR FIXED PRICE PPAS?

A. Given the Commission's prior rejection of RMP's attempt to reduce the maximum standard term for fixed price PPAs, the current maximum standard term for fixed

[15] Indeed, by practice RMP will not even provide a QF with a non-binding indicative pricing proposal if the commercial operation date is more than 39 months out. *See* RMP's Response to WIEC-TR 10.1. Given the length of time it is taking the Company to conduct interconnection studies, a QF might find itself in the position of paying the Company tens of thousands of dollars for interconnections studies without having an understanding of its possible avoided cost pricing.

price PPAs for QFs is twenty years. This means that a Wyoming QF can elect to sign a fixed-price twenty-year contract at the Company's avoided cost. RMP is proposing to reduce the maximum standard term to just seven years.

Q. WHAT IS THE COMPANY'S RATIONALE FOR REDUCING THE MAXIMUM STANDARD TERM?

A. Mr. Tourangeau claims that the current contract term of twenty years for QFs leads to poor economic outcomes and violates the "customer indifference standard." He argues that twenty-year QF contracts expose the Company's customers to "significant risk" because QFs are tied to resources that do not go through the "rigorous planning process" of the IRP.[16] Mr. Tourangeau also argues that because QFs are not chosen through a competitive process, there is no assurance that only least-cost, least-risk resources are added when the IRP demonstrates a need. He also asserts that QF resources expose customers to additional "significant potential costs" due to the must-take provision in PURPA, which requires a utility to dispatch QFs even if a less expensive option is available through economic dispatch.[17] Mr. Tourangeau claims that switching to a seven year maximum PPA length will still allow QF developers reasonable opportunities to develop renewable generation under PURPA in Wyoming.[18]

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[16] Direct Testimony of Mark P. Tourangeau, p. 4.
[17] *Id.*, pp. 4, 9-15.
[18] *Id.*, p. 5.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S PROPOSAL TO REDUCE THE MAXIMUM STANDARD TERM FOR FIXED PRICE PPAS FROM TWENTY YEARS TO SEVEN YEARS?

A. RMP's proposal to reduce the maximum standard term for fixed price contracts for QFs from twenty years to seven years should be rejected by the Commission. The Company's proposal is neither reasonable nor in the public interest.

Q. PLEASE ELABORATE.

A. RMP is once again asking that the Commission abandon its policy of reasonably encouraging QF development by ensuring the availability of long-term avoided cost contracts. In its place, the Company seeks adoption of a new policy designed to hinder further QF development in Wyoming. In supporting its argument, the Company relies on inapt comparisons and selectively subjects QF pricing to specific utility planning criteria, while ignoring the fact that the Company is compensated for its owned resources in a fundamentally different and far more favorable manner than the QFs.

Let me first place the Company's proposal in a recent historical context. I was an active participant in RMP's recent Energy Vision 2020 cases, in which RMP proposed to undertake both new wind[19] and wind repowering[20] projects on a massive scale, based not on a need for new energy resources but on perceived economic opportunity. In those cases, RMP proposed to add 1,311 MW of new

[19] Docket No. 20000-520-EA-17.
[20] Docket No. 20000-519-EA-17.

wind projects at a capital cost of $1.46 billion[21] and repower 999 MW of existing wind facilities at a capital cost of $1.10 billion,[22] the large majority of which was approved by the Commission.[23] I am also currently a witness in the Company's Foote Creek CPCN proceeding, in which the Company is proposing to replace existing wind facilities with 46 MW of new facilities at a capital cost of approximately $60 million, plus $4 million for removing existing turbines.[24] In light of my experience in those cases, I am struck by the glaring double standard advocated by the Company when it comes to the need for the long-term assurances of cost recovery for renewable energy development. As I will explain below, when it comes to Company-owned projects, RMP's position is that long-term cost recovery over the life of the project is essential. But, in contrast, QFs are somehow supposed to make do with seven-year deals. Yet the Company's own recent actions demonstrate the fallacy of its contention that seven-year deals are reasonable for new wind projects: on February 6, 2019, the Company filed a Notice of Exception with the Oregon Public Utilities Commission indicating that the Company had just entered into a new 120-MW (presumably non-QF) PPA with the Cedar Springs wind project in Wyoming. Not surprisingly, the new PPA that RMP negotiated, and for which it is seeking an exception to Oregon's competitive bidding rules, is

[21] Docket No. 20000-520-EA-17, Second Supplemental Testimony of Chad A. Teply, p. 3.
[22] The $1.10 billion capital cost assumes transmission interconnection agreements in WY are not modified. *See* Docket No. 20000-519-EA-17, Supplemental Direct Testimony of Timothy J. Hemstreet, p. 7 and Supplemental Direct Testimony of Rick T. Link, p. 19.
[23] 1,150 MW of new wind and 922 MW of repowered wind was ultimately approved.
[24] Docket No. 20000-553-EN-19, RMP Application, pp. 4, 7.

for a 20-year fixed price term.[25] So despite the Company's recommendation to the Commission regarding the appropriate length of QF contracts, when it comes to its own negotiations, RMP obviously recognizes that a long-term contract is essential for getting a new wind project developed.

Q. WHEN IT COMES TO COST RECOVERY FOR RMP-OWNED RENEWABLE PROJECTS, WHAT POSITION DOES RMP TAKE?

A. A salient feature of RMP's Energy Vision 2020 proposals was that the Company would not proceed with those projects without assurance from the Commission that the Company would recover the capital and operating costs of the associated investments, proposing to effectively obligate customers to a thirty-year commitment on $2.56 billion of investment (total Company).[26] Over and above this major regulatory commitment, in order to proceed with the repowering project, RMP also required assurances that it would be permitted to recover the cost of – and return on – the wind assets that were being retired early. The long-term regulatory protections that RMP insisted were necessary for it to proceed with the major renewable energy developments in Energy Vision 2020 provide a stark juxtaposition with the Company's claims in this case that QFs should be limited to seven-year PPA terms. The obvious double standard in the Company's advocacy

[25] PacifiCorp's Notice of Exception under OAR 860-089-0100 filed with the Oregon Public Utilities Commission, February 6, 2019. The 120-MW Cedar Springs PPA is in addition to the 200-MW Cedar Springs PPA approved in Docket No. 20000-520-EA-17.

[26] The Commission approved stipulations in Docket No. 20000-519-EA-17 (December 21, 2018 Memorandum Opinion, Findings, and Order Approving Stipulation) and Docket No. 20000-520-EA-17 (October 8, 2018 Memorandum Opinion, Findings, and Order Approving Stipulation) including cost caps based on a slightly modified set of projects.

simply does not pass the "straight face" test.

Q. WHAT IS YOUR RESPONSE TO RMP'S ARGUMENT THAT ITS RENEWABLE PROJECTS ARE SUBJECT TO A RIGOROUS IRP PROCESS WHEREAS QFS ARE NOT?

A. This is not a credible argument at the current time. RMP's recent history is replete with applications by the Company for Commission approval of renewable projects that were not thoroughly vetted by the IRP process, much less carrying the assurance of being least-cost and least-risk resources. Indeed, each of the three major renewable projects for which RMP has requested Commission approval in the past two years – wind repowering, new wind, and Foote Creek replacement – bypassed the rigors of the IRP process.

Q. PLEASE EXPLAIN.

A. RMP's 2017 IRP public input process began on June 21, 2016, and consisted of seven public input meetings and five state-specific meetings. However, the Company did not inform parties of its proposed repowering projects until March 2-3, 2017, at the final public meeting before the IRP was filed on April 4, 2017. The timing of this announcement afforded stakeholders little opportunity for meaningful input on these projects during the development of the IRP.

It is my understanding that the magnitude of the contemplated new wind projects, enabled by the Aeolus-to-Bridger/Anticline transmission line, was also announced at the final public meeting on March 2-3, 2017.[27]

The Company's abrupt announcement impeded the ability of stakeholders to evaluate these projects during the IRP development process, as underscored by the Public Utility Commission of Oregon's IRP docket order:

> In making this decision on PacifiCorp's Energy Vision 2020 action items, we share Staff's and the intervenors' struggles with the abrupt presentation of PacifiCorp's plan and rigidity of its procurement proposal. PacifiCorp's procurement plans presented in pre-IRP planning meetings changed dramatically to what the company proposed in its filed IRP and supplemental analysis. This left many stakeholders unable to support the 2017 IRP, as they had little chance for input and for comparing the proposal with alternatives.[28]

The Utah Public Service Commission expressed similar concerns in its acknowledgement of the Company's IRP:

> We acknowledge that the 2017 IRP substantially complies with the Guidelines. We also recognize that PacifiCorp's timing in completing and making available to parties its Energy Vision 2020 analysis deprived parties of a reasonable opportunity to evaluate that substantial element of its IRP. Accordingly, *we view Energy Vision 2020, including its effects on other aspects of the plan, to be less credible for IRP purposes* than the remaining IRP components. [29]

In the case of Foote Creek, RMP is seeking a CPCN for the Foote Creek I replacement project, despite the fact that this project was not fully evaluated in the IRP.[30] While a preliminary assessment of the replacement project in the 2017 IRP Update indicated potential for customer benefits, this preliminary assessment does

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[27] *See* Docket No. 20000-512-EA-17, RMP August 11, 2017 Reply Comments. IRP Public Input Process documents are available at: http://www.pacificorp.com/es/irp/pip.html.
[28] Oregon Docket No. LC 67, April 27, 2018 Order at 9.
[29] Utah Docket No. 17-035-16, March 2, 2018 Utah PSC Report and Order at 45. Emphasis added.
[30] *See* Docket No. 20000-553-EN-19, WIEC Exhibit 300.3, for RMP Response to WIEC Data Request 1.6; *see also* 2017 IRP Update, filed May 1, 2018, p. 119.

not appear to provide the same robust analysis that would be provided through a comprehensive IRP analysis. Indeed, the IRP Update stated that the Company would "explore this opportunity further in the 2019 IRP;"[31] however, the 2019 IRP has since been delayed, leaving the Commission and intervenors in the Foote Creek proceeding trying to analyze the proposal on an accelerated basis without the benefit of the robust IRP analysis.

Given the fact that RMP has largely sidestepped a rigorous IRP vetting of its own multi-billion-dollar wind projects, I would argue that the pricing for QFs actually has a *closer* nexus to the IRP in many respects than do the Company's own recent renewable projects. The QF nexus is closer because avoided capacity costs are calculated directly from the IRP deferrable resources, whereas the Company has shown a penchant for advancing its own renewable projects as "special opportunities" that are brought forward largely outside a thorough vetting in the IRP process, Mr. Tourangeau's assertions notwithstanding.

Q. WHAT IS YOUR RESPONSE TO RMP'S ASSERTION THAT BECAUSE QFS ARE NOT CHOSEN THROUGH A COMPETITIVE PROCESS, THERE IS NO ASSURANCE THAT ONLY LEAST-COST, LEAST-RISK RESOURCES ARE ADDED?

A. RMP's argument fails to recognize that the price paid to QFs represents the Company's *own cost projections* from the preferred portfolio in its IRP, which has already taken into account the cost-effectiveness of planned resource additions.

[31] 2017 IRP Update, filed May 1, 2018, p. 119.

Essentially, the Company is brushing aside the previous body of work developed in Wyoming to ensure fair QF pricing and ratepayer protection in accordance with the partial displacement differential revenue requirement ("PDDRR") pricing method, a method that was championed by the Company and which provides prices for QF projects that are directly derived from comparison to the Company's least-cost plan. Indeed, in advocating for adoption of the PDDRR method in Docket No. 20000-388-EA-11, RMP stated that "this approach fairly values Wyoming QFs as they compare to other real alternatives available to the Company through its IRP."[32] The Company's position in the current case ignores its own prior assessment of the ability of the PDDRR method to accurately and fairly measure avoided cost for long-term contracts.

In fact, in that prior generic QF case, RMP advocated for adoption of the PDDRR method as a means to provide reasonably-priced twenty-year contracts to QFs. As RMP stated in its Application in that case:

> The Company is confident that removing these limitations which exist in the current pilot avoided cost methodology will not impose additional risk on existing customers or result in avoided cost prices that are too high or unreflective of the avoided cost because the methodology is self-correcting in that it does not commence the application of a capacity deferral credit to the QF until the year in which new capacity is needed. Once a new QF is added, the capacity need is pushed out to reflect the addition of that new QF to the system.[33]

[32] Docket No. 20000-388-EA-11, RMP Application, p. 5.
[33] *Id*., p. 7.

Q. WHAT IS YOUR RESPONSE TO RMP'S ARGUMENT THAT QFS SUBJECT RATEPAYERS TO SIGNIFICANT RISK BECAUSE QFS ARE TIED TO RESOURCES THAT DO NOT GO THROUGH THE IRP'S "RIGOROUS PLANNING PROCESS"?

A. In advancing this argument, the Company is conveniently overlooking the fact that the structure of compensation and risk is fundamentally different for a QF than it is for the Company. The Company's argument fails to recognize that performance risks of QF projects are largely borne by the QF developers themselves, not ratepayers. In contrast, if RMP's wind projects perform at levels that are less than expected, which has been typical in the past,[34] there is no reduction to the Company's capital cost recovery for the under-performing project outside of a finding of imprudence, which is a very high bar. But if a QF project performs at levels that are less than expected, there is an automatic reduction in payment to the QF because the QF only gets paid for its output. Similarly, if the operating and maintenance costs of a Company project run higher than expected, these costs are recoverable from customers in a general rate case, unless there is a finding of imprudence, but a QF must absorb higher-than-expected costs in its margins, prudent or not.

Indeed, as a general matter, the obligations of customers are more open-ended when it comes to paying for utility-owned plant in contrast with QF

[34] *See* Docket No. 20000-519-EA-17, Redacted Direct Testimony of Kevin C. Higgins (adopted by Courtney Higgins), pp. 27-28.

contracts.

Q. PLEASE EXPAND UPON THIS LATTER POINT.

A. Utility generation assets are subject to ongoing environmental risks that are commonly addressed through environmental upgrades which customers are routinely required to fund pursuant to general rate case decisions. Customers are also at risk when the life of utility-owned plant is shortened. This may result in increased annual depreciation expense over the remaining life of the asset, or as witnessed in the repowering case, continued rate recovery for retired wind assets when the wind sites are repowered. In contrast, a QF under a long-term contract must absorb the cost of future upgrades and other investments without recourse to additional ratepayer funding. Thus, when it comes to recovering lifetime plant investment costs, the playing field is already unequal in the utility's favor and disadvantageous to ratepayers with respect to the utility-owned assets. The PDDRR method does not give any weight to this risk avoidance benefit from QFs because the method accepts the Company's least-cost plan without adjusting for the fact that RMP can seek approval for recovery of subsequent unanticipated investment in its plants during their lifetimes. The omission of this utility risk consideration in QF pricing suggests that the PDDRR method actually errs on the side of ratepayer *benefit* rather than ratepayer *indifference* when it comes to lifetime recovery of plant investment. The Company ignores this risk-mitigating feature of current QF pricing in its arguments in this case.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S COMPLAINT THAT THE MUST-TAKE PROVISION IN PURPA REQUIRES A UTILITY TO DISPATCH QFS EVEN IF A LESS EXPENSIVE OPTION IS AVAILABLE THROUGH ECONOMIC DISPATCH?

A. This is another example of an inapt comparison. Because the Company-owned wind projects are assured of cost recovery through base rates irrespective of output levels in a given hour, at the margin (i.e., in the dispatch stack) the cost of the energy from these Company-owned resources appears nearly free except for integration costs. Consequently, there is seldom a perceived need to curtail Company-owned wind on economic grounds. Indeed, market prices would have to be *negative* before it makes sense to even consider economically curtailing most Company-owned wind plants, particularly if the wind facilities are generating PTCs. Moreover, the Company does not suffer a cost recovery disallowance if it curtails its own wind plants or any other of its own units. But because QFs do not have the same fixed cost recovery protections as RMP, there is a positive price attached to QF wind (and solar) output – for that is the only basis upon which QFs get paid. Mr. Tourangeau complains about paying QFs on a "must take" basis. Yet meanwhile, the Company's owned wind facilities operate close to "must take" because their marginal costs are so low due to the highly-protected regime of fixed cost recovery that the Company enjoys. Rather than being "must take" as a result of a favorable cost recovery regime like RMP has, QF output is "must take" by law because QFs only get paid by making sales; if utilities could use their discretion to refuse the

QF's power they could drive them into bankruptcy through predatory market practices. The statutory "must take" requirement protects the QF and the public interest against this hazard.

Q. WIEC IS A CUSTOMER ADVOCACY GROUP. WHY IS WIEC OPPOSING RMP'S EFFORTS TO LIMIT QF CONTRACT TERMS TO SEVEN YEARS?

A. As a customer advocacy group, WIEC supports keeping power prices at the lowest reasonable levels. To that end, WIEC views competitive power suppliers, including QFs, as helping to reach that objective, because among other things, competitive power suppliers provide an incentive for the monopoly incumbent to perform more efficiently. All things being equal, the lower a utility is able to keep its cost of production, the more difficult it is for a competitive supplier to beat the utility's costs and displace the utility's future investment opportunities. Competitive suppliers like QFs also take on project performance risks that are otherwise typically borne by customers for utility-owned facilities. WIEC views RMP's proposal to limit QF contract terms to seven years as a means for the Company to quash competition in the provision of generation supply to customers in Wyoming. This is neither good for ratepayers, nor for the competitive market in Wyoming.

Q. WHAT ARE THE FINANCIAL IMPLICATIONS FOR QFS IF MAXIMUM CONTRACT TERMS ARE SHORTENED TO JUST SEVEN YEARS?

A. All things being equal, reducing the contract term to just seven years will obviously make it more difficult for QFs to obtain financing that would reasonably support project development. But it is not just the term itself that matters, it is the term *and* the pricing. As demonstrated in Mr. MacNeil's testimony, the seven-year mark represents a significant inflection point in avoided cost pricing using the PDDRR method for contracts beginning in 2021: avoided cost pricing during the first seven years of the twenty-year contract period is significantly lower than the subsequent years, as the later years show an increase in projected avoided cost starting in 2028, coincident with the assumed retirements of the Dave Johnston, Naughton, and Jim Bridger Unit 1 coal plants.[35] By combining a dramatically shortened term with rock-bottom pricing that cuts off the analysis just prior to major expected IRP events, the Company's proposal appears intended to ensure that no new QF PPAs can go forward, particularly when taken in tandem with the drawn-out interconnection study process that projects must endure.

Q. ARE TWENTY-YEAR CONTRACTS PRODUCING UNREASONABLY HIGH PRICING FOR WYOMING QFS?

A. No. For the [redacted] of Wyoming solar QF projects that have signed contracts, but have not yet gone into service, the average projected PPA price is [redacted] per MWh.[36] For the Wyoming solar QF projects that have requested pricing, but do not yet have a signed PPA, the average projected PPA price drops to just $32.36 per MWh for twenty years.[37]

The prices are even lower for wind QFs. For the [redacted] of Wyoming

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[35] Direct testimony of Daniel J. MacNeil, pp. 15-16, 18, and 21-22.
[36] This calculation is shown in CONFIDENTIAL WIEC Exhibit 300.2/Two Rivers Wind Exhibit 500.2.
[37] This calculation is shown in WIEC Exhibit 300.3/Two Rivers Wind Exhibit 500.3

wind QF projects that have signed contracts, but have not yet gone into service, the average projected PPA price is just [redacted] per MWh.[38] And for the Wyoming wind QF projects that have requested pricing, but do not yet have a signed PPA, the average projected PPA price is just $25.99 per MWh for a twenty-year deal. These power prices compare favorably to what customers pay RMP for power.[39] The all-in generation cost for which RMP was granted recovery in Wyoming in the most recent general rate case was approximately $49.49 per MWh.[40]

Q. IN SUPPORT OF HIS ARGUMENT TO SHORTEN CONTRACT TERMS MR. TOURANGEAU CITES TO A DECISION BY THE MONTANA PUBLIC SERVICE COMMISSION ("MONTANA PSC") TO SHORTEN QF CONTRACT TERMS TO TEN YEARS. WERE THERE ANY SUBSEQUENT DEVELOPMENTS ON THIS ISSUE IN MONTANA?

A. Yes. In an Order on Reconsideration issued November 24, 2017, the Montana PSC modified the order cited by Mr. Tourangeau and increased the maximum contract length for QFs up to 3 MW from ten years to fifteen years.[41] However, on April 2, 2019, the Montana Eighth District Court, Cascade County, ("Montana District Court") found that the Montana PSC acted arbitrarily and unreasonably in reducing

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[38] This calculation is shown in CONFIDENTIAL WIEC Exhibit 300.2/Two Rivers Wind Exhibit 500.2.
[39] This calculation is shown in WIEC Exhibit 300.3/Two Rivers Wind Exhibit 500.3
[40] Sources: Generation revenue requirement at requested return: Docket No. 20000-469-ER-15. Compliance Class Cost of Service Model Workpaper, Unit Cost - Target Worksheet, Total Wyo. Generation Revenue Requirement (Line 14). Wyo. Energy at Input: Wyo. PSC Docket No. 20000-469-ER-15. Compliance Class Cost of Service Model Workpaper, Energy Factor Worksheet, Total Wyo. Energy @ Input (Line 30). Note: The all-in generation cost includes a small proportion of QF power.
[41] Montana PSC Docket No. D2016.5.39, Order No. 7500d. *See especially* paragraph 30. Order 7500d also eliminated the five-year fixed-price limit referenced in Mr. Tourangeau's direct testimony on page 8, lines 12-14.

QF contract terms from twenty-five years to fifteen years and reinstated the twenty-five-year contract term.[42] Moreover, the Montana District Court found that the actions of the Montana PSC were undertaken improperly for the purpose of eliminating competition.

> To balance the power of the monopolistic system and the public interest, power companies in Montana are regulated by The Public Service Commission, which is to independently and fairly balance the legitimate interest of the power company in a fair profit for its shareholders with the interests of the public. Absent fair balancing by the Commission, compensation rates to renewable energy developers could be set in a manner to, effectively, make such renewable energy development economically unfeasible, and thereby eliminate competition. This could happen by either reducing rates or contract lengths. That is what happened here.
>
> …
>
> The Commission arbitrarily cut rate and contract lengths by about half and effectively made it economically impossible for solar and wind facilities to do business… [43]

The findings by the Montana District Court that the shortened contract terms were aimed at stifling competition speaks to the very same concerns that WIEC has with regard to the Company's proposal in this case.

Proposed modifications to RMP's avoided cost methodology

Q. WHAT METHOD DOES RMP USE TO CALCULATE AVOIDED COSTS IN WYOMING?

A. RMP uses the PDDRR method to calculate non-standard avoided costs under Schedule 38, which is generally applicable to larger and higher-capacity factor QFs.

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[42] Montana Eighth District Court, Cascade County, Cause No. BVD-17-0776, Order Vacating and Modifying Montana Public Service Commission Order Nos. 7500c and 7500d, April 2, 2019 at 2, 13.
[43] *Id*. at 2, 3.

In this proceeding, RMP is also proposing to use the PDDRR method to calculate avoided costs under Schedule 37, which is generally applicable to smaller and lower capacity-factor QFs.

Q. ARE YOU FAMILIAR WITH THE PDDRR METHOD?

A. Yes, I participated in the avoided cost proceeding in Wyoming in which RMP initially proposed the PDDRR method, and in subsequent proceedings in which the PDDRR was addressed.

Q. GENERALLY, HOW DOES THE PDDRR METHOD CALCULATE AVOIDED COST?

A. The PDDRR method is an IRP-based approach to determining avoided cost which provides prices to QF projects that are directly derived from comparison to the Company's least-cost plan. The method is designed to pay QFs the same costs that the Company avoids based on its long-term least-cost plan.[44] Specifically, to calculate avoided costs, two GRID model runs are performed, one reflecting the current IRP resource portfolio, and a second one with the QF project seeking pricing included as a resource and the next deferrable proxy resource decremented by the size of the QF. In Wyoming, the proxy resource for wind QFs is a proxy wind plant. For non-wind QFs, the proxy resource is a thermal plant with adjustments for capacity-equivalent contributions. The difference in the two GRID

[44] Because the costs of Company-owned resources are recovered from customers over longer periods than QF contracts (e.g., 40 years for thermal unit versus 20 years for a QF contract) and the cost recovery of Company-owned assets is front-end loaded, the capacity cost to ratepayers over the first fifteen years of a Company-owned asset is actually greater than the capacity cost to ratepayers of a fifteen-year QF contract that is based on the avoided cost of that same Company-owned asset, all things being equal. This is due to the unequal time periods for recovery.

runs forms a portion of the value created by adding the QF to the portfolio. The other portion, the capacity deferral value, is based on avoiding the fixed cost of the next deferrable proxy plant in the IRP. The avoided cost price in the QF's PPA can be levelized over its term, in which case the future values of avoided energy and capacity are discounted back to current dollars.

Q. WHAT MODIFICATIONS TO THE PDDRR METHOD IS RMP PROPOSING FOR CALCULATING AVOIDED COSTS FOR RENEWABLE QFS?

A. As I stated above, in Wyoming, the proxy resource for wind QFs is a proxy wind plant, and for non-wind QFs, the proxy resource is a thermal plant with adjustments for capacity-equivalent contributions. In this proceeding, RMP is proposing a modification that would determine the applicable proxy resource to be the next deferrable resource *of the same type* as the QF in the Company's IRP preferred portfolio. Whereas this modification would not impact the proxy used for wind QFs in Wyoming, it would introduce a solar proxy for solar QFs, and renewable QFs with relatively flat load profiles (e.g. biomass, biogas, hydro, and geothermal) would be eligible to displace IRP resources of like type.

Baseload resources would be eligible to defer thermal resources, and renewable QFs would also be eligible to defer thermal resources if no renewable resources of the same type (as the QF) remain in the IRP preferred portfolio. Although there are no thermal resources in the 2017 IRP Update preferred portfolio, baseload resources would be eligible to defer front office transactions.[45] In addition, in the years prior to deferral of a proxy renewable or thermal resource, all QFs would be eligible to defer front office transactions identified in the IRP preferred portfolio.[46]

Q. WHAT IS YOUR ASSESSMENT OF RMP'S PROPOSAL TO LIMIT THE DEFERRAL OF A RENEWABLE RESOURCE TO RESOURCES *OF THE SAME TYPE* AS THE QF?

A. I have a general concern with this limitation, although my concern is mitigated in current circumstances. My general concern is that this limitation could prevent a renewable QF from being fairly compensated for its ability to defer renewable plants that the Company is planning to add, solely because the QF's resource type differs from the resource type that the Company is planning to add next in its IRP. Implicit in RMP's advocacy for these restrictions is the notion that the Company is somehow unable to partially (or wholly) defer a wind plant, say, when a solar QF timely comes on line, and vice versa. This premise strikes me as highly implausible. When considering adding new resources in its IRP, the Company must consider the impact of long-term QF contracts on the need for Company-owned capacity after taking account of the capacity characteristics of the QF resources. This evaluation must be performed irrespective of QF resource type. The idea that new solar QF contracts would have no influence on whether Company-owned wind

[45] Direct Testimony of Daniel J. MacNeil., p. 9.
[46] *Id.*, pp. 6-7.

resources need to be added in the future seems very unlikely.

Q. WHY IS YOUR CONCERN MITIGATED UNDER CURRENT CIRCUMSTANCES?

A. So long as the next deferrable resource for a wind QF occurs relatively close in time to the next deferrable resource for a solar QF, then neither resource type would be unfairly disadvantaged by limiting eligibility for displacement to resources of the same type. In such circumstances I agree it would be expedient to use RMP's "like for like" approach for wind and solar QFs.

As it turns out, at the current time, the next deferrable resources for both wind and solar occur in 2030, according to Mr. MacNeil.[47] Therefore, although I have general concerns with RMP's "like for like" limitations, my concerns are allayed *at the present time*, given the Company's current indications of when its planned wind and solar plants will next be deferrable.

Q. WHY ARE YOU CONCERNED IF THE TIMING OF THE NEXT DEFERRABLE WIND AND SOLAR RESOURCES DIVERGE SUBSTANTIALLY?

A. If the timing of the next deferrable wind and solar resources substantially diverge, then I am concerned that the Company's proposal would potentially result in arbitrary disadvantages being conveyed to QFs whose resource is deferrable in the IRP at the later date. This matter is a concern because the value of deferred capacity is discounted in the calculation of the avoided cost payment. All things being equal,

[47] *Id*., pp. 14-15.

the later the deferral occurs, the smaller the avoided cost payment. For example, if the IRP shows the next deferrable wind resource is in 2030, but the next deferrable solar resource is not until 2034, then under RMP's "like for like" proposal, a solar QF would not be given credit for a capacity deferral until 2034, even though the IRP shows that there is deferrable wind four years sooner, in 2030. Even though the solar QF and the deferrable wind proxy have different output shapes, the solar output would still be able to displace some portion of the planned wind energy and wind capacity on a capacity-equivalent basis. However, RMP's proposal does not allow for such a displacement in the avoided cost calculation.

Q. WHAT IS YOUR RECOMMENDATION REGARDING RMP'S PROPOSED "LIKE FOR LIKE" RESTRICTION?

A. In circumstances in which the next deferrable resources for wind and solar QFs occur relatively close in time, such as within two years of each other, it would be reasonable to use RMP's "like for like" convention to calculate avoided cost for wind and solar QFs. However, if the timing of the next deferrable wind and solar resources begin to diverge substantially, then the expediency of adhering to this convention must be weighed against the potential arbitrary disadvantage conveyed upon a QF whose resource is deferrable in the IRP at the later date. In such circumstances, the Commission should retain reasonable flexibility to allow the "like for like" convention to be waived and to permit wind and solar QFs to obtain avoided cost pricing based on the next deferrable renewable resource, irrespective of QF type, on a capacity-equivalent basis. I suggest that such waivers be considered when the timing of the next deferrable wind and solar resources diverge by more than two years.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE PROPOSED "LIKE FOR LIKE" CONVENTION OTHER THAN THE TIMING OF THE NEXT DEFERRABLE WIND AND SOLAR RESOURCES?

A. Yes, I also have some concerns regarding the implications for cogeneration QFs. First, it seems that cogeneration QFs should be eligible for deferring the Company's planned investment in geothermal resources, since cogeneration and geothermal are both baseload resources. Second, I am not convinced that it makes sense to ignore that fact that cogeneration may impact the Company's planned development of wind and solar resources. Although I am not recommending that the Commission reject the "like for like" convention for determining the avoided cost of cogeneration QFs, I believe the Commission should also show flexibility in the future if a cogeneration QF can reasonably make the case that its project defers the need for new RMP solar or wind in the IRP, and potentially to allow the determination of avoided cost on that basis.

Q. IS RMP PROPOSING TO MAKE ANY OTHER CHANGES TO ITS AVOIDED COST METHOD?

A. Yes. Mr. MacNeil proposes to calculate Schedule 37 avoided costs using the same PDDRR method used for Schedule 38. He also proposes to redefine on-peak and off-peak hours in the QF payment calculation such that hours in which the average price is greater than the monthly average for all hours are considered on-peak, while those hours in which the average price is less than the monthly average for all hours are considered off-peak.[48]

Q. WHAT IS YOUR RESPONSE TO THESE PROPOSALS?

A. I do not object to either of these proposals. With regard to the first issue, it strikes me as reasonable to calculate Schedule 37 and Schedule 38 avoided costs on a consistent basis. With regard to the second issue, the change to on-peak and off-peak definitions is intended to improve price signals for payments to QFs without changing the total expected avoided cost payments to a QF as currently calculated using the PDDRR method for Schedule 38. It thus appears to be an attempt to fine tune actual payments to better correspond to market value by hour.

Other Tariff Changes

Q. PLEASE DESCRIBE THE OTHER TARIFF CHANGES RMP PROPOSES.

A. RMP is proposing:

(i) language in Schedules 37 and 38 stating that providing a pro-forma PPA does not mean the QF is at the PPA negotiation phase;

(ii) language in Schedules 37 and 38 stating that the Company has the right to update pricing any time prior to execution and filing of the PPA with the Commission;

(iii) additional specific tariff provisions stating that the QF commercial operation date (or the delivery term of subsequent PPAs for existing QFs) must

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[48] *Id*., pp. 23-26.

not exceed 30 months from PPA execution date and that a QF must provide project development security within 30 days of the PPA being filed with the Commission; and

(iv) language stating that after RMP acquires 10 MW of Firm Power resources under Schedule 37, pricing for QFs larger than 100 kilowatts will be in accordance with Schedule 38 until Schedule 37 prices are updated, and adding language to make it clear that PPA negotiations will be carried out in accordance with the PPA negotiation requirements detailed in Schedule 38.

Q. WHAT IS YOUR RESPONSE TO THE PROPOSED TARIFF CHANGES?

A. With the exception of item (iii), the proposed tariff changes are either unnecessary or else harmful to the public interest in that the change would unreasonably shift the PPA negotiation leverage to RMP's advantage.

Q. WHICH PROPOSED LANGUAGE CHANGE IS UNNECESSARY?

A. The language in item (i) above is unnecessary. Section I.B.6 of Schedule 38 already states, in relevant part:

> *After reviewing the draft power purchase agreemen*t, the owner shall prepare an initial set of written comments and proposals regarding the draft power purchase agreement and shall provide such comments and proposals, or notice that it has none, to the Company. *The Company shall not be obligated to commence negotiations with a QF owner until the Company has received an initial set of written comments and proposals from the QF owner*. [Emphasis added.]

Since the written comments and proposals from the QF owner are submitted *after* the pro-forma PPA has been provided by RMP, the proposed language indicating that "providing a pro-forma PPA does not mean the QF is at the PPA negotiation phase" is unnecessary.

If not seen as unnecessarily redundant, RMP's proposed language may make it unreasonably difficult for QFs to establish the existence of a legally enforceable obligation ("LEO") under PURPA. QFs may establish that a LEO exists between the QF and RMP that obligates RMP to purchase the QFs power under PURPA in the absence of an executed PPA. While I am not a lawyer, my understanding is that the FERC has recognized that LEOs are intended to prevent public utilities such as RMP from avoiding its PURPA obligations by refusing to sign a contract, or delaying the signing of a contract, so that a later and lower avoided cost is applicable.[49] The FERC has also viewed unfavorably state PURPA rules that enable public utilities to control whether and when a legally enforceable obligation exists.[50] Here, where RMP already retains a certain amount of power to withhold a negotiable PPA from QFs under Schedule 38,[51] I am concerned that RMP's proposed language could be used by the Company to argue against the

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[49] *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 at P 36 (2011) ("…the phrase legally enforceable obligation is broader than simply a contract between an electric utility and a QF and that the phrase is used to prevent an electric utility from avoiding its PURPA obligations by refusing to sign a contract, or as here, from delaying the signing of a contract, so that a later and lower avoided cost is applicable. We further find that Idaho PUC's June 8 Order ignores the fact that a legally enforceable obligation may be incurred before the formal memorialization of a contract to writing.").

[50] *FLS Energy, Inc.*, 157 FERC ¶ 61,211 at P 27 (2016) ("We find that, just as requiring a QF to have a utility-executed contract, such as a PPA, in order to have a legally enforceable obligation is inconsistent with PURPA and our regulations, requiring a QF to tender an executed interconnection agreement is equally inconsistent with PURPA and our regulations. Such a requirement allows the utility to control whether and when a legally enforceable obligation exists — e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement. Thus, the Montana Commission's legally enforceable obligation standard is inconsistent with PURPA and our regulations under PURPA.").

[51] For example, by practice, RMP will not provide a negotiable PPA to a QF (1) if the commercial online date is more than 39 months out, or (2) prior to the completion of a Feasibility Study, System Impact Study, or Facility Study for the project. *See* RMP Responses to WIEC-VK-TR 7.1 and 7.2, which are included in WIEC Exhibit No. 300.1/Two Rivers Wind Exhibit No. 500.1.

existence of a LEO.

Q. WHICH PROPOSED LANGUAGE CHANGES WOULD UNREASONABLY SHIFT THE PPA NEGOTIATION LEVERAGE TO RMP'S ADVANTAGE?

A. The language in items (ii) and (iv) above would unreasonably shift the PPA negotiation leverage to RMP's advantage. Starting with item (ii), RMP should not be granted a unilateral and open-ended ability to update PPA pricing at *any time* prior to execution. Such broad discretion is unreasonable and potentially subject to abuse. Currently, Section I.B.6 (c) of Schedule 38 provides that RMP "shall update its pricing proposals *at appropriate intervals* to accommodate any changes to the Company's avoided-cost calculations, the proposed Project or proposed terms of the draft power purchase agreement." [Emphasis added.] The reference to "appropriate intervals" implies that reasonable standards must be applied to the timing of any PPA pricing updates. For example, in determining avoided cost in Wyoming, the queue of QFs ahead of the QF seeking pricing does not include QFs without a signed PPA. It is thus understood that a newly-signed PPA with another QF could be the basis for refreshing a PPA price. Similarly, an official update to the IRP could also be a reasonable trigger for updated pricing. The tariff should retain the current reference to "appropriate intervals" and should not be modified to grant RMP the unrestricted ability to change PPA prices whenever it wants during the negotiation process.

Arguably, the language in item (iv) is also unreasonable because it undermines the purpose of Schedule 37, which is to provide published rates for purchases from smaller QF projects. Under RMP's proposal, Schedule 37 would effectively be converted to Schedule 38 – and its case-by-case analysis and negotiation process – as soon as 10 MW of Schedule 37 purchases were under contract. This change would make smaller QFs subject to Schedule 38 requirements until a new Schedule 37 rate could be calculated and approved. This encumbrance on smaller QFs strikes me as unnecessary.

In fairness, the current tariff also limits the availability of the published rates to 10 MW; thus, the Company's proposal does not introduce this limitation, but rather provides an alternative approach to be used when the 10 MW threshold is reached. This qualification notwithstanding, I believe the preferred option here is simply to eliminate the 10 MW cap (which appears on page 3 of Schedule 37). Wyoming does not appear to be awash with small projects seeking approval under Schedule 37. If the 10 MW threshold is reached, RMP should be free to file an update. Otherwise, there is no reason to cap the availability of Schedule 37 to only 10 MW. The Company already plans to update the rate on an annual basis.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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 CONTRCT TERM OF PURPA POWER PURCHASE AGREEMENTS	DOCKET NO. 20000-545-ET-18 (Record No. 15133)

AFFIDAVIT, OATH AND VERIFICATION

STATE OF UTAH)
) SS:
COUNTY OF SALT LAKE COUNTY)

Kevin C. Higgins, being first duly sworn, on his oath states:

1. My name is Kevin C. Higgins. I am a Principal in the firm of Energy Strategies, LLC. I have been retained by the Wyoming Industrial Energy Consumers and Two Rivers Wind, LLC to testify in this proceeding on their 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-ET-18.

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

Kevin C. Higgins
Energy Strategies, LLC
215 South State Street, Suite 200
Salt Lake City, Utah 84111

Subscribed and sworn to before me this 17th day of April, 2019.

Millicent Pichardo
Notary Public
Commission #: 700882

My Commission Expires: June 13, 2022

Notary Public - State of Utah
Millicent Pichardo
Comm. #700882
My Commission Expires
June 13, 2022