KENNECOTT EXHIBIT 2.9

Docket No. 20000-545-ET-18
Witness: Mark P. Tourangeau

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Mark P. Tourangeau

May 2019

Q. Are you the same Mark P. Tourangeau who previously submitted direct testimony in this proceeding on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes. I filed direct testimony supporting the Company's application ("Application") to modify certain commercial aspects of Wyoming's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA").

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the Company asking the Commission to approve in this proceeding?

A. The Company seeks several changes to PURPA implementation, including; a reduction in the maximum allowable contract term for qualifying facility ("QF") power purchase agreement ("PPA") contracts from 20 years to seven years, improvements to the language and process for QFs under the Company's Schedules 37 & 38 tariffs, and improvements to the avoided cost pricing methodology.

Q. Please summarize your initial direct testimony.

A. My initial testimony presented and supported the Company's proposed modifications to Schedule 37, Avoided Cost Purchases from Qualifying Facilities, and Schedule 38, Avoided Cost Purchases from Non-Standard Qualifying Facilities. These modifications improve the implementation of PURPA Schedule 38 in a number of ways while reducing risk to the Company's customers.

First, a reduction in the fixed price contract length for non-standard QF PPAs under the Company's Schedule 38 tariff and Firm Power Time of Delivery QF PPAs under the Company's Schedule 37 tariff will mitigate risk to customers. I provided supporting evidence and discussed why a shorter term length for QF PPAs is fairer to

the Company's customers, consistent with PURPA's customer indifference standard, while remaining consistent with PURPA's requirement that QF developers have a reasonable opportunity to attract capital for their Wyoming projects.

Second, clarifying the processes, procedures and language in the Company's proposed revisions to Schedules 37 & 38 will provide greater transparency in avoided cost pricing requests and PPA negotiation and execution procedures. The proposed clarifications to the processes and procedures in the Company's Schedules 37 & 38 will minimize confusion among potential QFs.

Q. Which witnesses' testimony are you responding to in your rebuttal testimony?

A. My rebuttal testimony focuses on the following testimonies: a) Kevin Higgins, who provided testimony jointly for the Wyoming Industrial Energy Consumers ("WIEC") and Two Rivers Wind, LLC ("Two Rivers Wind") (collectively "WIEC/Two Rivers"); b) John Lowe who provided testimony for the Renewable Energy Coalition ("REC"); c) The joint testimony of Drs. Marc Hellman and Lance Kaufman who provided that testimony on behalf of both REC and the Rocky Mountain Coalition for Renewable Energy ("RMCRE"); and d) The testimonies of Hans Isern and Mark Klein, each provided for RMCRE.

Q. After reading intervenors' direct testimony in this docket, what are your general observations?

A. Much of the REC, RMCRE, and the WIEC/Two Rivers testimonies cover common themes in response to the Application. Generally speaking, the witnesses allege that the true goal of the Application is to severely limit QF development. This is not true, the Company understands its obligations to purchase QF power under PURPA's rules as

promulgated by the Federal Energy Regulatory Commission ("FERC") and the Public Service Commission of Wyoming ("Commission"). At the same time, the Company's central obligation is to provide its customers with safe, reliable and affordable power. The Application represents the Company's continuing efforts to balance these two, at times competing, obligations.

Q. Please summarize your understanding of the REC and RMCRE testimony with respect to the points raised concerning your initial testimony.

A. RMCRE is an un-incorporated, informal coalition that was formed with the sole purpose of opposing the Company's efforts in this proceeding. The current supporters of RMCRE are sPower, VK Clean Energy, and Chevron Power and Energy Management Co. REC is a trade group that was established in 2009 and is comprised of members that develop, own and operate QFs in the western United States. In their testimony, RMCRE's and REC's representatives make the following high level points:

RMCRE and REC both argue the Commission should reject the reduction of the QF PPA contract term for any period of time less than 20 years. They claim that QFs cannot obtain financing with seven year fixed price contracts, and that limiting contracts to seven years would be anti-competitive. RMCRE witnesses Mr. Isern and Mr. Klein claim that the shorter terms would impair QFs' ability to achieve financing/capital and discourage QF development.

At the same time, the witnesses solely testifying for REC appear to represent smaller scale QFs, and decry the lack of financing for their projects. These witnesses completely ignore the USDA financing programs identified in my direct testimony. Mr. Klein for RMCRE, on the other hand identifies the USDA programs but disregards

them as more applicable to small QFs. REC's witnesses also claims that shorter term contracts make it difficult to operate small hydro facilities and to plan for maintenance capital and spend time and money on re-negotiation of PPAs. The Company is interested in speaking with the owners and operators of small hydro generating resources that can deliver to its service areas to see if there are mutually beneficial solutions for them outside of QF contracts. As is clear from my discussion on PURPA's must take obligation as it relates to the non-dispatchable nature of QFs, PURPA's limited flexibility may be leaving potential value on the table for both the Company and these small hydro resources.

Q. Please summarize your understanding of Kevin C. Higgins' direct testimony for WIEC/Two Rivers with respect to the points raised concerning your initial testimony.

A. While Mr. Higgins' testimony makes many of the same points as those made by RMCRE and REC, he also raises a couple of unique points worth addressing here individually.

Q. How is your rebuttal testimony organized?

A. My testimony focuses on rebutting several topics that REC, RMCRE, and WIEC/Two Rivers each provided testimony on, and then it rebuts two issues raised only by WIEC/Two Rivers' witness Mr. Higgins.

THE RISKS OF OVERLY LONG QF PPA TERMS

Q. Did the REC, RMCRE, and WIEC/Two Rivers testimonies properly characterize the discussion of risks associated with entering into long term PPAs with QFs?

A. No. Direct testimony from each of these parties missed the point the Company made regarding long-term QF PPA risk, economic dispatch vs uneconomic dispatch, and the harm that such long term QF contracts can cause our customers. Instead of taking these arguments head on, these parties attempted to confuse the issue by focusing much of their testimony on the Company and its return on invested capital. QFs cause more risk to our customers, and mitigating this risk is at the heart of the Application's proposal to shorten the maximum QF PPA term length. By shortening the term length the Company seeks to restore the balance between the principle inherent to PURPA that customers should be no worse off buying from a QF than they would be buying the same amount of energy from their utility (the "customer indifference principle"), and the Company's strict adherence to PURPA's other requirements. This case does not present the Commission with a decision about how the Company may or may not generate return on invested capital. Instead, the Application asks this Commission to determine whether shorter term QF contracts reduce risks to customers while still allowing QFs a reasonable opportunity to attract capital.

Q. Are fixed price contracts the only way to reduce risk?

A. No. After providing an elaborate description in testimony of the ability of fixed price QF contracts to reduce risk,[1] witnesses Hellman and Kaufman admitted, in response to RMP data request 1.20, that options also reduce risk. The ability to economically

[1] REC & RMCRE, Direct Testimony of Dr. Marc Hellman and Dr. Lance Kaufman, at pp. 8-12.

dispatch is an option available only with Company owned resources and non-QF PPAs that reduces risk. Over the longer term, Company owned resources give the Company the option to change its portfolio in response to changes in resource costs and expected future conditions, which is also hindered by long term, non-competitive fixed price contracts like 20 year QF PPAs.

Q. How do you respond to the assertions from REC and RMCRE witnesses Hellman and Kaufman that shorter term contracts increase risks for customers rather than mitigate them?

A. Witnesses Hellman and Kaufman assert that long term fixed price QF contracts are less risky because they lock in prices for the Company's customers and thus reducing price variability. They note that our customers only pay for the power that is generated. They claim that there is no risk to the Company or our customers when a QF defaults under its PPA or when it experiences operational issues. Hellman and Kaufman further claim that customers will never have to worry about the impacts from a QF coming online past its contractual commercial operation date ("COD") or shutting down prior to the expiration of its contract.

One of the purported risks referred to repeatedly by REC, RMCRE, and WIEC/Two Rivers stems from comparing the Company's ability to recover capital investments in owned-resources vs how QFs operate. However, this comparison is neither apt, nor does it address the evidence the Company has put forth in favor of a reduction to the maximum QF contract term. In my direct testimony I refer to the price risk to our customers from 20 year QF contracts. The price risk comes from two areas.

The first is that these long term contracts are not based on a competitive procurement.[2] This risk accrues to the customers through net power costs in the variance between the prices of these contracts versus other power costs over the term of the contract. Of course this risk applies to both QF and non-QF long term contracts but the difference is that non-QF contracts are typically priced through a competitive process. The resulting positive variance between the PPA and net power costs are reduced, or even go negative compared to an avoided cost based QF PPA that generally has a higher absolute price.

The second risk stems from the must-take obligation in these contracts.[3] When the Company refers to impacts to net power costs in the EIM relative to the "must-take" provision of a QF, what we are referring to is the opportunity to displace a higher cost resource with a lower cost import. For example, if prices in the EIM are $10/MWh and a thermal unit has a cost of $18/MWh, that unit can be decremented from its original schedule and displaced with the $10/MWh import at a benefit to customers of $8/MWh. Similarly, if the QF contract states that PacifiCorp must pay it $35/MWh for every MWh, but prices in the EIM are $5/MWh, PacifiCorp does not have the opportunity to displace the QF schedule for the cheaper import. Due to the fact that the EIM is only a within-hour market, these intra-hour EIM prices are not included in the avoided cost pricing model, which is an hourly model. Even if the model was an intra-hour model, the Company does not currently have an "EIM" price curve since it is within-hour opportunities that are primarily related to imbalances across the system (e.g. solar over-

[2] Rocky Mountain Power, Direct Testimony of Mark P. Tourangeau, at p. 14 lines 4-7.
[3] *Id.,* at pp. 12-13, lines 22-23 & 1-13.

producing in the real-time market versus forecast on a day-ahead basis, or lower loads versus day-ahead forecasts).

Avoided cost models are forecasting models and cannot measure what the impact to market prices are when forecasts are wrong. The imbalances that result when forecasts are wrong in real-time can create opportunities to monetize benefits in the EIM using resources that the Company has the ability to dispatch up and down for our customers' benefit. These opportunities do not exist with QFs due to their must-take provisions, which ultimately harms the Company's customers.

Q. Can you provide a specific example of how these benefits are forfeited due to a QF must-take contract?

A. Yes. In 2017 and 2018, a 140.7 MW nameplate capacity QF in Wyoming experienced 6,519 and 2,163 five minute intervals of negative pricing respectively. Due to the project being a QF, the resource was required to be dispatched during these intervals instead of being decremented to allow lower-priced resources or transactions to be used to serve the Company's customers. The total cost to customers due to this must-take obligation over the two years was $327,506. This is the cost to our customers in 2017 and 2018 associated with just one of the 166 QFs on PacifiCorp's system, totaling almost 2,000 MWs of nameplate capacity. These are real costs that increase customers' rates vs what they could be, and demonstrate the harm to customers from the lack of dispatchability associated with the Company's must-take PURPA obligations.

The negative impacts of QF non-dispatchability hits customer prices in our 6 states through various net power cost adjustment mechanisms such as the Energy Cost Adjustment Mechanism and Energy Balancing Account, and impact customer rates. By

shortening the terms of QF contracts, improvements in avoided cost calculations to better account for the impact of the EIM market and other factors can be incorporated when a contract is renewed, reducing the absolute difference between the PPA prices and actual avoided costs.

Using the definition of risk from REC's witnesses Hellman and Kaufman, which is stated as variance,[4] shortening fixed price QF contract lengths –will increase the Company's options to respond to changing future conditions and reduce risk for customers. Having more options reduces the risk to the Company's customers and better aligns the allocation of risk between QFs and customers in accordance with PURPA's customer indifference principle.

Q. Do REC and RMCRE witnesses' discussion of risks associated with QFs miss any key risks?

A. Yes. RMCRE and REC's witnesses contend that QFs are less risky than utility owned resources since QFs can only receive pricing based on avoided costs of the utility. They claim that QFs bear all costs of project development including cost overruns, that, should a QF be decommissioned early, ratepayers do not continue to pay, and that if a QF comes online late the developer must pay delay damages. All of these claims ignore a key point—that if a QF defaults due to any of the reasons above and fails to come online or ceases operations early, it is the Company and its customers who will bear the risk of replacing the defaulted QF capacity.

[4] *See*, Direct Testimony of Marc Hellman, Ph.D. and Lance Kaufman Ph.D. on behalf of Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy, at pp. 9-11, lines 15-19, 1-17, and 1-5 respectively.

Q. What other key QF risks does the REC, RMCRE, and WIEC/Two Rivers testimony fail to fully account for?

A. REC, RMCRE, and WIEC/Two Rivers witnesses each claim that the Company's concerns over the "must take" obligation and "economic dispatch" costs borne by our customers are incorrect and irrelevant to the contract term length. RMCRE's witness Mr. Isern claims that my testimony seeks to create an "apples to oranges" comparison between utility owned generation and the Company's return on capital vs. QFs, while totally ignoring the impacts to our customers. In fact, my testimony stresses the "apples to apples" comparison of costs to our customers in a given settlement period on the system. This comparison demonstrates the risks associated with the must take obligation that causes higher priced QF energy to be used in a given period versus the low to negative price alternatives available from company owned resources, contracted resources, or transactions available in the EIM.

Testimony from REC, RMCRE, and WIEC/Two Rivers repeatedly fails to address non-dispatchability, and their witnesses instead attempt to re-direct the Company's arguments about "must-take" and "economic dispatch" into a discussion on capital recovery for company-owned resources. These are diversionary tactics, not evidence that counters the Company's concerns about QF non-dispatchability. The Company consistently points to the risk to our customers that stems from PURPA's must take obligation, and our efforts to reduce the risks to our customers via the proposals made in the Application. These parties instead point to unrelated issues, versus squarely addressing the real risks that the Company has identified.

PROCURMENT USING IRP PROCESSES AND TOOLS YEILDS POSITIVE BENEFITS TO CUSTOMERS, QFS ARE ONLY INTENDED TO MAKE CUSTOMERS NO WORSE OFF

Q. Did the REC, RMCRE and WIEC/Two Rivers testimonies properly describe how the Company identifies and selects new non-QF energy resources?

A. No. Testimony from each of these parties shows a basic lack of understanding of the procurement process for non-QF resources, all while trying to conflate this process with the QF process. Company resource procurement, and the QF PPA process exist under entirely different regulatory regimes that were established for distinct purposes. The Company's non-QF procurement process results in significantly lower risk for the Company's customers, in part because the Company risks cost disallowance if its procurement of non-QF resources—either owned or contracted—do not result in customer benefits and are not implemented and maintained prudently.

Q. Are there other differences between the Company's non-QF resource procurement and QFs?

A. Yes. As I have noted, the Company has an obligation to provide its customers with safe, reliable and affordable power. It uses several tools through its IRP processes to identify its customers' needs and the best resources and opportunities to meet those needs. The non-QF procurement process generally arises from the Action Plan part of the Company's IRP, and, at times, outside of the Action Plan to take advantage of significant market opportunities, which opportunities the Company uses IRP tools to evaluate customer benefits. In contrast, the QF PPA process, mandated by PURPA,

effectively provides non-utility generators that meet the law's qualifications a "put" option to utilities with little to no ability on the part of utilities to plan in advance to acquire QF resources based on customer needs. While the Company understands PURPA's federal mandate is ongoing, the law initially sought to alleviate issues in the US energy market that no longer exist. These changed circumstances are among the reasons why the Company has asked the Wyoming Commission to use its authority under PURPA to modify its implementation so that it better reflects the current environment.

Q. What is your response to the assertion from REC, RMCRE, and WIEC/Two Rivers witnesses that non-QF procured resources result in more risk to customers than QF procured resources?

A. This is an area where the witnesses mischaracterize or willfully ignore the scope of the Company's non-QF resource procurement processes. My initial testimony described at a high level the IRP process and resulting resource acquisition strategy traditionally followed by the company.[5] REC, RMCRE, and WIEC/Two Rivers witnesses pointed out different occasions where the Company procured resources outside of this process —for example, the Cedar Creek III wind PPA. The Company acknowledges that the IRP Action Plans are not always followed systematically with respect to non-QF resource acquisitions, and the Company, at times, must act quickly to take advantage of time-limited opportunities to generate benefits for customers. However, the Company also evaluates the customer benefits associated with such opportunities using the IRP information and tools.

[5] Tourangeau Direct, at pp.9-11, lines 17-22, lines 17-22, 1-24, and 1-21 respectively.

With respect to the Cedar Creek III PPA, the Company acted on the opportunity to acquire an additional PPA for 120 MW of capacity in Wyoming as a result of the Energy Vision 2020 2018R RFP. In early November 2018, NextEra Energy Resources ("NextEra") approached PacifiCorp with an offer to engage in PPA discussions, with similar terms and conditions as contained in the Cedar Springs I PPA from Energy Vision 2020, for the incremental 120 MW Cedar Springs III opportunity.

Cedar Creek III must be in service by December 31, 2020 to qualify for federal production tax credits ("PTCs"). To achieve this in-service date, construction activities must begin no later than May 2019, which required a PPA to be executed quickly. Executing the PPA enabled NextEra to finalize certain contractual arrangements (i.e., turbine-supply agreements and engineer, procurement and construction agreements) that were required to achieve a commercial-operations date of no later than December 31, 2020. Failure to execute the Cedar Springs III PPA within this time frame risked forgoing the opportunity to secure a low-cost wind resource that will provide a unique value for customers. Signing this PPA will result in anywhere from an estimated $38m to $84m in net present value revenue requirement benefits to the Company's customer from 2021 through 2038. This is in contrast to similarly long QF contracts that generate $0 forecasted economic benefits to customers due to their pricing at avoided costs, and provides another example of how a re-balancing of risk is necessary to ensure that customers remain indifferent to QF contracts.

Q. What are some other differences between Company procurement and the QF PPA process?

A. Another important point to consider when attempting to compare the Company's

resource acquisitions to QFs is that, unlike QF developers, the Company faces significant scrutiny with respect to the prudency of these actions, and disallowance risk on capital investment or non-QF PPA acquisitions. Commission scrutiny provides a strong disincentive against unnecessary investments or contractual commitments.

The witnesses also try and frame the operations and credit risks as the same or less for QFs vs company-owned or non-QF PPAs, but here we disagree as well. The Company faces the same types of disallowance risks for cost-overruns and performance issues for these contracts as they do for initial approvals to treat them as system resources. Contrast this with QFs, who face the same sort of operational and environmental risks as a company owned or non-QF PPA asset.

REC, RMCRE, and WIEC/Two Rivers witnesses are correct that these are borne by the QF owners. But only up to a certain point. In response to Company discovery, Mr. Higgins responded that the customers would be indifferent to the choice of replacement, but that is only if avoided cost forecasts equal actual costs for energy and capacity at the time of the default.[6] Other witnesses did not directly answer. Isern stated that the relevant Commission would decide who bears the replacement cost and Hellman/Kaufman provided a similarly indirect answer.[7] In fact, the cost of the replacement capacity and energy would be borne by the Company's customers, and any variation vs the original avoided cost, or risk, would accrue to the customers. QFs are not subject to a prudency review on where their projects are sited, their proposed budgets vs what they actually spend, the quality of their construction and equipment,

[6] *See*, Response to Company's WIEC/Two Rivers Data Request 1.3.
[7] *See*, Response to Company's RMCRE Data Request 1.5; and Response to Company's REC & RMCRE Data Request 1.24.

or any other aspects of a normal prudency review faced by the Company for non-QF procured resources. And yet the ultimate risk of replacing the capacity and energy does not fall on the QF owner as it typically does for the Company, it accrues to the Company and ultimately its customers.

Q. Is it the Company's position that QFs are often more risky for customers than resources the Company contracts for through competitive solicitations?

A. Yes. While REC, RMCRE, and WIEC/Two Rivers would have you believe that there is less risk associated with QFs, in reality the requirements for non-QF resource providers are more stringent and ensure a lower risk profile for our customers.

QFS DO NOT PROVIDE MEANINGFUL COMPETITION TO COMPANY PROCURMENT

Q. Does PURPA introduce price competition into Wyoming's generation market?

A. No. REC, RMCRE, and WIEC/Two Rivers testimony all claim that PURPA introduces competition into the generation market in vertically integrated utility territories.[8] However, this is not competition from a price/customer risk perspective, because third party QFs are not required to provide energy at prices that are better than the Company's, they merely have to be viable at the Company's avoided costs. In other words, a QF will proceed and be paid for by customers if it can be developed at a price that is only "as good as" the price at which the Company estimates it could provide the same amount of energy to customers. Absent the risks inherent in such estimation, and the other risks discussed in my direct testimony, the "competition" cited by these parties provides zero price benefits to customers. Considering the other risks I have

[8] *Id.*, at pp. 36-37; and WIEC/Two Rivers, Direct Testimony of Kevin C. Higgins, at pp. 19 & 24.

discussed surrounding long-term QF PPAs, and customers may actually end up worse off.

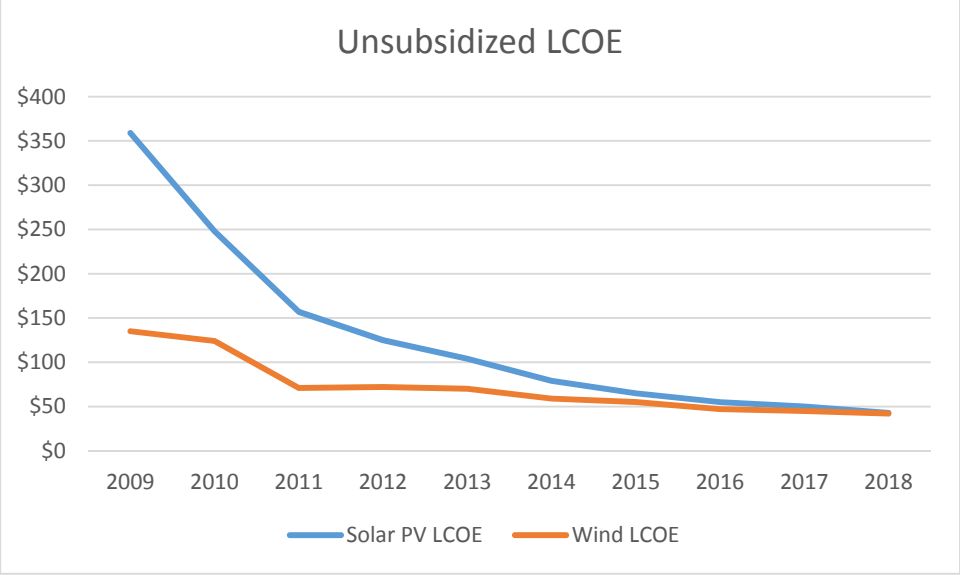
Instead of the creative interpretation of "competition" advanced by REC, RMCRE, and WIEC/Two Rivers, real competition with tangible benefits to customers comes through solicitations for resources and the competitive bidding process that ensues. Through the non-QF procurement process, the Company, and other stakeholders, have a much greater say over the caliber of developers who provide non-QF resources, and can better ensure higher levels of operational experience and creditworthiness to ensure that customers and the utility get the resources they are counting on. PURPA's 1978 mandates, which do not require QFs to demonstrate any net benefits to customers is not comparable.

Q. The intervenor witnesses talk about the benefits that QFs bring to customers via their direct competition with Company-owned resources. Is this competition beneficial for customers, and how does it compare to other means for procuring resources through the markets?

A. One of the basic goals of PURPA when it was passed in 1978 was to allow third party generators to install generation in vertically integrated utility territories, while ensuring that the utilities' customers were indifferent to the costs of either source of generation. This was the only way at the time, given the lack of deregulation in the electricity markets, to introduce competition into what had traditionally been considered a natural monopoly. It was akin to a centrally planned economy trying to introduce some initial free market concepts into the industry. This goal, combined with the other goals of PURPA to pursue energy independence and promote the growth or renewable energy,

helped keep a check on utilities' costs of owning and operating generation 30 to 40 years ago.

In terms of true competition though, PURPA, as originally conceived, only goes part way. Given that the pricing construct for PURPA essentially puts a price floor on generation capacity and energy for QFs, ensuring they receive no less than what it costs a utility to buy or build their own generation, it allows the QFs to extract excess rents from the market if the utility's method for calculating avoided costs is not aligned with or keeping up with the market. The graph below, using data from Lazard investment bank, shows how the levelized costs of energy ("LCOE") for utility scale photovoltaic solar and wind technologies have changed over the last 10 years.[9] The values in the table reflect the *unsubsidized* values for each technology, meaning the costs for utility scale solar and wind are not reduced by the $/MWh value of the ITC and PTC respectively.



[9] https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.

This situation has the following impacts on the Company's customers with respect to QFs. First, the biennial nature of the IRP process sometimes makes it impossible to keep up with the fast changes in the market, and second, by locking in avoided costs in 20 year contracts, our customers are subject to costs that do not reflect the market, even at the time the pricing was set, for many years into the future. The witnesses for RMCRE, REC, and WIEC/Two Rivers point out the benefits of the 'competitive' QF landscape, but this is a dated construct that does not recognize the further deregulation and evolving market dynamics that have revolutionized the United States electricity markets—even in vertically integrated utility territories. Perhaps these arguments were valid in 1979, or even in 1989, but they ring hollow 30 years later.

True competition for the utility comes from competitive solicitations that we issue to procure non-QF generation resources, and the recent success the Company had with the 2017R RFP demonstrates how this competition is benefitting our customers. This competition manifests itself even during the competitive solicitation process. During the 2017R RFP, the benefits to the Company's customers increased as the bidding progressed from the initial short list to the submission of best and final offers, as explained in Rick T. Link's testimony in Wyoming Docket No. 20000-520-EA-17.[10]

> The data shown in this figure for the updated economic analysis have the same basic profile as the data from the original economic analysis summarized in my direct testimony. This profile shows that despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits, reduce the magnitude and shorten the duration over which costs increase after federal PTCs for new wind resources expire, and continue to contribute to customer benefits over the long-term.

[10] *See,* Supplemental Direct Testimony of Rick T. Link, Wyoming Docket No. 20000-520-EA-17.

In order to restore customer indifference to ensure the Company's customers are not subject to these ongoing higher costs for long periods of times versus other alternatives available in the competitive market, it is imperative to shorten the contract length to seven years.

Q. What mechanisms ensure that the Company will act in its customers' best interests when it comes to Company sponsored solicitations for new energy resources?

A. There are two key things that provide the Company with strong incentives to ensure that the resources it procures are least cost and least risk. First, the Company takes its duty to provide reliable and affordable power to its Wyoming customers very seriously. Second, the Company faces significant disallowance risk from regulators if it acts imprudently on behalf of its customers. The Company's service obligation when coupled with the scrutiny of regulators, which includes the risk of cost disallowance, provides very effective incentives to ensure the Company only devotes its capital to prudent projects that will be used and useful in service to its customers.

A SEVEN YEAR PPA TERM PROVIDES QFS REASONABLE OPPORTUNTIES TO ATTRACT CAPITAL

Q. After reading the witnesses' testimony, how do you respond to their assertions that seven year contracts are 'un-financeable'?

A. As FERC affirmed in *Windham Solar*, PURPA implementation by the states must allow reasonable access to capital for QFs.[11] Reasonable access does not mean that the implementation must guarantee financings at the best rates and terms possible. A seven

[11] 157 FERC 61,134 at P. 8.

year contract does not automatically make QFs un-financeable. Avoided cost pricing that is above competitive market pricing allows for economic rent extraction by QFs (a privilege not available to other market participants); in conjunction with a reasonable fixed term of seven years, this provides a sufficiently reasonable ability to attract capital. This ability is enhanced by the strong credit quality of the cash flows from these PPAs which are backed by the diversification benefit of millions of utility customers and regulated utilities' generally strong credit ratings, a fact that QF developers enjoy pointing out in their investor materials.[12]

Under the Company's proposed seven year term, these advantages to QFs, coupled with the nimbleness and flexibility of the capital markets, and the vast sums of money currently chasing renewables deals, will provide Wyoming QFs reasonable opportunities to attract debt financing that PURPA requires. While some QFs may not achieve the high leverage levels and or the same returns that they have enjoyed at 20 year terms, and project sponsors may have to put more of their own equity at risk, this is not unreasonable and therefore is not a violation of PURPA.

Q. What evidence can you cite to support the idea that the QF's concerns over financing are overstated?

A. The renewables industry is replete with examples of new financing structures being developed to adapt to changes in the industry. Tax equity financing is a great example.

[12] On February 7, 2018 sPower issued a press release stating they recently closed a $421.4 million 4(a)(2) private placement on a portfolio of 565 MW of utility scale solar and wind assets. sPower CEO Ryan Cramer is quoted as saying "This first-of-its-kind milestone is a testament to the quality of our operating portfolio, the relationships we have with our finance partners and the strength of our utility offtakers. This financing will benefit sPower for years to come by locking in predictable cash flows for almost two more decades." In December 2017, Project Finance International named this financing their "Deal of the Year" for the renewable energy category. Available at , http://www.spower.com/news_2018/news-2018-02-07.php (last accessed October 11, 2018).

Entities such as investment banks or large industrial conglomerates with the appetite for tax credits—used to offset earnings and allow them to pay lower federal and/or state income taxes—pay for those tax attributes, thereby providing funding for developers who don't have the same tax credit appetite due to a lack of earnings or a stockpile of existing credits that they cannot use in current or near future tax years. Given the copious Investment and Production Tax Credit ("ITC" and "PTC") incentives enjoyed by renewables developers, the tax equity market has been a key financing pillar in the growth of the industry. And when the developers began setting up YieldCos—an innovative financing structure mirrored off of master limited partnerships used by pipeline companies, which both take advantage of unique tax laws and ongoing streams of cash flows—they worked with tax equity partners to further refine the tax equity market through the use of pay as you go ("PAYGO") tax equity structures[13].

PAYGO tax equity structures are tax equity financings that provide cash flows over time to the developers and their YieldCo companies in exchange for tax attributes instead of a single upfront payment (thus the term PAYGO). Another example, referenced by Mr. Isern in his direct testimony, would be to package these deals as part of a syndicated financing with longer term PPAs from other markets to achieve a longer weighted average contract length.[14] While these syndicated loans may not achieve quite as favorable financing terms as would a structure with a longer weighted average contract length, the addition of PPAs with extremely secure cash flows due to the high

[13] NextEra Energy Partners Investor Presentation, page 23. http://www.investor.nexteraenergypartners.com/~/media/Files/N/NEP-IR/news-and-events/events-and-presentations/2017/10-30-2017/nep-october-2017-investor-presentation-vfinal2.pdf.

[14] *See*, Direct Testimony of Hans Isern on behalf of Rocky Mountain Coalition for Renewable Energy, at pp. 12-13, lines 248-255.

quality of the underlying customer credit, would, I suspect, compete very well. And again, the purpose of PURPA is to allow access to capital markets, not to create the lowest cost debt, and therefore greatest profits possible, for QF developers.

There are yet other avenues for financing small QFs, as I pointed out in my direct testimony, including the USDA's Rural Development and Rural Energy for America Programs. In his testimony, RMCRE's Mr. Klein claimed that these programs are not available to QF developers, later in response to discovery he admitted that his point was really that they do not work for the sorts of QFs that his company develops, because his projects are utility scale solar sites developed on leased property.[15] In other words his testimony did not consider small QFs developed by farmers or ranchers on their own land and to supplement their cash flows and provide renewable energy to the grid.

Lastly, given that the federal tax incentives for wind and solar renewables assets are rolling off over the next couple of years via federal legislation passed in the Tax Extender bill in late 2015 (brokered by major renewables developers and equipment manufacturers) the importance of longer PPA terms required to enable tax-equity financings will no longer be needed. So while RMCRE's Isern and Klein point to the need for longer term PPAs to support these tax equity financing structures in their testimony, in reality once these incentives have rolled off, the market will likely return to a more traditional project financed or syndicated loan market with more flexible terms and conditions. And the developers will have access to this capital at good terms, even under seven year contracts. QF developers may just have to be a little more

[15] Response to Company's RMCRE Data Request 1.21.

creative and work a little harder to bring solid projects to the capital markets for financing.

The fact that a project with a 25 to 30 year life cannot be solely debt-financed for a seven year term without a meaningful equity stake is unsurprising. The Company's proposed seven year contract term accounts for the uncertainty and risk in future avoided costs and that uncertainty is well-known to capital markets. A 20 year contract term unfairly imposes that risk on customers who receive no expected benefits in return at the avoided cost price.

Q. Did REC, RMCRE, or WIEC/Two Rivers provide reliable evidence that a seven year term was insufficient to allow QFs a reasonable opportunity to attract capital?

A. No. RMCRE testimony sought to differentiate the types of financing available to utility-scale QF developers that bundle multiple 80 MW projects into mega renewables development sites versus the truly small power generation that PURPA was meant to support. None of these parties offered testimony disputing the fact that billions of dollars are available to renewables developers in the United States. Similarly, none of these parties countered the evidence presented in my direct testimony demonstrating that capital markets are creative and flexible, and will adjust to changes in underlying regulation and deal structures in order to continue to allocate capital to opportunities to earn returns.

Q. What is the fundamental difference between a 20 year contract term and the Company's proposed seven year contract term?

A. With a 20 year contract term, the Company's customers are guaranteeing a payment

stream that reflects expected benefits far into the future and are thereby deprived the opportunity to pursue more cost-effective options. With a seven year contract term, a developer can still expect to receive benefits far into the future, but the exact benefits are not guaranteed. To the extent the avoided cost forecast is as accurate as possible, which is what the Application seeks to accomplish, developers should still have reasonable opportunities to attract capital without forcing retail customers to guarantee payments far into the future, because those estimates should give them a reasonable sense of expected earnings in subsequent contract terms.

Q. Does RMCRE's Mr. Isern accurately characterize your testimony regarding alternatives to 20 year contract terms?

A. No. Mr. Isern's direct testimony discusses PPAs signed by corporate buyers for sustainability goals that may be less than 20 years in length.[16] He claims that such contracts are not comparable to QF PPAs, stating, without any substantiation, that corporations must pay a premium for these agreements to facilitate the developer to signing a shorter term contract.

Mr. Isern also states that the PPAs cited in my testimony are all in organized markets where power can be freely liquidated and there are a "whole host" of contracting opportunities after the expiration of an initial PPA. In my prior role at NextEra Energy Resources managing over 40 utility scale wind assets in the organized markets of the Southwest Power Pool ("SPP") and the Electricity Reliability Council of Texas ("ERCOT"), I found the opposite to be absolutely true; attempting to re-contract a 15 to 25 year old renewable asset with obsolete technology was incredibly

[16] RMCRE, Direct Testimony of Hans Isern, at p. 11.

difficult in organized markets with competition from new technology with lower installed costs and better technology. In his testimony, Mr. Isern notes that lenders assign little to no value to an asset at the end of a 20 or 25 year contract term because of this fact. Yet, at the same time, Mr. Isern contradicts himself stating that there are a "whole host" of re-contracting opportunities. Mr. Isern ignores the legal realities, which is that a QF has a distinct advantage over renewable resources in organized markets. Under PURPA, a QF retains the right to put an asset with a 25 to 30 year life to the Company under additional long term contracts at avoided cost prices, even after earning most of their return during the initial contract term. This legal right to force utilities to enter into subsequent contracts once the initial term has expired is a huge advantage for QFs over merchant facilities in organized markets.

THE COMPANY'S 30 MONTH PPA EXECUTION POLICY IS REASONABLE, REGARDLESS OF WHY A QF'S COD MAY BE DELAYED

Q. Is the Company's application seeking any change to the QF interconnection process in Wyoming?

A. No. REC, RMCRE, and WIEC/Two Rivers witnesses all expressed disagreement with the Company's proposal in its revisions to Schedule 38, which commits to writing its long standing policy not to execute a QF PPA if a QF's COD is more than 30 months out. While these parties all point to the interconnection process and the time that process can take as a reason to either not adopt this restriction, or to modify the 30 month period, the policy arises out of considerations that are purely commercial.

There are a whole host of reasons that a QF developer may run into delays that require it to push out its COD. These reasons can include the timing of the

interconnection study process, but they also include permitting, securing land rights, financing, and construction or equipment delays. With respect to the interconnection process, the Company has long understood that it can take a long time. It is for this reason that the current version of Schedule 38 contains the following exhortation to QF developers:

> It is recommended that the owner initiate its request for interconnection as early in the planning process as possible, to ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Wyoming Energy Service Schedule 38, Section II, ¶2. The Application's proposed revisions to Schedule 38 repeats this same language in the beginning of the tariff to better ensure that developers are made aware of the fact that the highly technical interconnection study process operates on a separate timeline from the commercial pricing and PPA negotiation process. Just as it is the developer's responsibility to have financing secured, permits in place, and construction and equipment supplies ready to meet its construction schedule, it is the developer's responsibility to ensure that its interconnection is well underway before seeking to finalize a PPA with the Company,

The 30 month policy is indifferent as to the cause of a delayed COD, and its focus is on customers who would otherwise be at risk of having to pay for QF PPAs at very stale prices if the company were to execute contracts with CODs too far into the future. The Company's policy, now proposed to be explicitly stated in Schedule 38, strikes a reasonable balance between the risk of stale pricing and the QFs need for time to build its project. In my 10 plus years of experience in the utility scale renewables markets, it is extremely rare for a site to require more than two years to achieve COD

from the time of PPA execution, unless there were specifically negotiated reasons for the longer time frame.

Q. Can you comment on the recommendation of Mr. Klein with respect to the Company's proposed inclusion of this policy in Schedule 38?

A. Yes. Mr. Klein attacks the Company's proposal. He urges the Commission to instead increase the 30 month time period to fifty-one months to account for the long winters in Wyoming and to adjust that period based upon any interconnection study delays, or to account for the risk that QFs cannot achieve their environmental or other permitting on a timely basis. Mr. Klein also claims that RMP has not demonstrated the current practice of negotiating the COD is in need of reform. RMP agrees on the last point, the policy against executing a PPA more than 30 months prior to a QFs COD has been part of the Company's practice in Wyoming since at least 2014, and including explicit language in its tariff will not change that. The policy itself, as noted in response to the earlier question, is indifferent as to the cause of a delayed COD, and protects customers from stale pricing. The risks of development delays should not be borne by the Company's customers, and speculative behavior by a QF should not be rewarded at customer expense.

Q. Why might a QF not achieve COD?

A. QF developers may speculatively enter agreements in anticipation of technology cost declines. If as construction approaches those cost expectations do not occur, they may choose not to construct and default on their agreement. The associated cost to customers of replacement resources is unlikely to be fully covered by the contractual

damage provisions. This is particularly true if the Company has foregone other more economic resource opportunities in the interim.

Q. What if technology costs decline?

A. If technology costs decline by more than the Company's forecast, avoided costs will be overstated relative to the non-QF resources the Company could acquire and customers will be worse off.

Q. What is the key link between these two negative outcomes?

A. Both of these situations are exacerbated by allowing for contract pricing and execution well in advance of COD. A QF project which is shovel-ready and commences construction soon after executing a PPA is much more likely to achieve COD than one which fully intends to gauge the market for a year or more before committing to construction.

OTHER STATES' PURPA IMPLEMENTATIONS OFFER HELPFUL GUIDANCE, BUT WYOMING'S PARTICULAR NEEDS PREDOMINATE

Q. Why do you think it is relevant to look to other states for their efforts to implement PURPA in a way that balances the requirements to purchase power from small power producers (as defined in PURPA) and the interests of customers?

A. It is instructive to look to other states to see how they have managed the influx of utility scale solar and wind generation under PURPA. Many states have seen large increases in installed capacity in their territories as their contract terms and avoided cost methodologies struggled to keep up with the rapid decrease in renewables LCOE's combined with the impacts of tax incentives. As I stated in my initial testimony, this

has caused real costs and real operational issues for utilities as they seek to integrate these resources into their daily generation dispatch.

Wyoming's situation is unique, as are the situations in each state, and thankfully PURPA allows Wyoming to implement rules and procedures that are appropriate for its unique economic and regulatory circumstances. States such as Idaho, North Carolina, Alabama, and Montana have looked for various solutions to achieve the right balance for their particular circumstances. Other states' approaches can be instructive, even if those solutions would need tailoring to fit within Wyoming's broader economic and regulatory structures. For example, the Company is closely watching the legislative solution in North Carolina, as Duke Energy Carolinas recently concluded their first round of competitive RFPs under HB 589 and North Carolina's Competitive Procurement of Renewable Energy ("CPRE") program, where Duke awarded 14 solar contracts for 602 MWs[17] out of the 78 bids that were received. According to reports from the independent administrator, Duke's customers will see savings of around $375m over the 20 year contract period versus avoided costs. [18] While the Company would not necessarily propose the exact same process be implemented in Wyoming, a program that successfully delivers better value for Duke's customers could inform future changes to PURPA implementation in Wyoming.

Q. Are REC, RMCRE, and WIEC/Two Rivers witnesses consistent in their analysis of how other states have implemented PURPA?

A. Not at all. On the one hand, these parties' witnesses question the relevance of the Company's references to laws and regulations passed in other states that have led to

[17] https://www.elp.com/articles/2019/04/duke-energy-selects-14-solar-projects-602-mw-in-all.html.
[18] *Id.*

shorter contract terms and/or competitive bidding processes. These witnesses erroneously state that the Company's arguments in support of its Application rest heavily on these decisions. On the other hand, one of their strenuous objections to the current Company proposal is based on a recent Montana District Court ruling overturning the Montana Public Service Commission's recent decision to shorten contract terms and adjust avoided cost prices.[19]

These witnesses fail to fully describe the procedural reasons the court overturned the decision. The major findings of the Court, in overturning the Montana Public Service Commission, were grounded in procedural deficiencies in the cases below. The court found that the Montana PSC failed to provide adequate notice on certain key contract length issues, failed to follow its own precedents, exceeded its statutory authority, and failed to gather the evidence needed to determine that the term length met Montana standards as set forth in Montana's statutes. REC, RMCRE, and WIEC/Two Rivers testimony on the Montana case all ignore the fact that the Commission, in considering the Application, can avoid the administrative and procedural errors that contributed heavily to the decision by the Montana Eighth Judicial District Court. Their testimony also ignores the fact that, unlike in the Montana case, nothing requested in the Application is inconsistent with Wyoming's PURPA related precedents and statutes.

REC, RMCRE, and WIEC/Two Rivers cannot have it both ways, how other states have implemented PURPA is not relevant when it favors one's position, and

[19] Montana Eighth Judicial District Court, *Vote Solar, Montana Environmental Information Center, Cypress Creek Renewables, LLC, and Windata LLC v. The Montanta Department of Public Service Regulation, Montana Public Service Commission, and Northwestern Corporation,* BDV-17-0776, 2019.

irrelevant when it does not. Instead, the policies of other states can provide the Commission useful information as to how particular policies have worked in other places, understanding that, before adoption, any such policies would need to be tailored to fit Wyoming's particular regulatory and economic circumstances, Even mistakes made in other states' implementation of PURPA can be useful counterexamples. The Montana case, for example, provides this Commission with an example of procedural deficiencies it should seek to avoid in this or future PURPA proceedings.

Q. Would it be appropriate for Wyoming to adopt the changes suggested by REC witness John Lowe, which would make Wyoming's Schedule 37 more consistent with Oregon's approach to small QFs?

A. No. Mr. Lowe points out that the equivalent to Schedule 37 is handled differently in other states where the Company serves customers, such as Oregon. However, Mr. Lowe provides no context to justify why Wyoming should make the same PURPA policy choices as Oregon, a state with a very different regulatory and economic environment than Wyoming. Wyoming has the right to implement PURPA in a manner that best balances the law's mandates against the needs and policies that are most likely to serve the interests of Wyoming customers.

MISCELLANEOUS REBUTTAL POINTS

Q. Is Mr. Higgins' testimony for WIEC/Two Rivers on the Company's ability to refresh avoided cost pricing any time prior to PPA execution consistent with Commission precedent?

A. No. Mr. Higgins objects to the Company's inclusion a provision in its proposed revisions to Schedule 38 stating that the company has the right to update QF pricing

any time prior to PPA execution. While the language is certainly new, the right is not. In a recent case involving a developer named Trireme Energy Development II, LLC, the Wyoming Commission affirmed this right, and expressed its desire that the Company ensure QFs receive the most up-to-date pricing possible prior to executing a PPA.[20] The Commission's order makes clear that its goal was to preserve the customer indifference principle.[21] The Company's goal in proposing this new language for Schedule 38 was not to expand its ability to refresh its avoided cost pricing, but rather to make the Commission's existing policy on such repricing clear to prospective Wyoming QFs to help avoid unnecessary disputes.

Q. Should the Commission incorporate all of the testimony and information in the previous Wyoming PURPA case filed by the Company in Docket No. 20000-481-EA-15 as Mr. Higgins suggests?

A. No. Mr. Higgins makes this suggestion based on the claim that, during the Commission ordered collaborative, the Company only "recycled" its proposals from the docket itself. Mr. Higgins claim is not true, but that is beside the point. The Company's application in this docket is not intended to rehash arguments and solutions proposed in the prior case. The Company filed the application to incorporate the most recent, relevant information necessary for the Commission to make an informed decision regarding the Company's requests, so the closed docket is relevant only to the extent it

[20] *See*, *In the Matter of the Amended Joint Complaint Filing by Trireme Energy Development II, LLC; Pryor Caves Wind Project LLC; Mud Springs Wind Project LLC; and Horse Thief Wind Project LLC Against Rocky Mountain Power and PacifiCorp Regarding the Avoided Cost Pricing for the Bowler Flats Wind Qualifying Facilities Power Purchase Agreements*, Docket No. 20000-505-EC-16 (Record No. 14579), Commission Order at ¶ 63 (Dec. 31, 2018).
[21] *Id.*

provided the Company the impetus to take a harder look at changes needed to PURPA implementation in Wyoming. The Application itself can and does stand on its own.

CONCLUSION

Q. Please summarize your recommendations based on your experience in the energy markets and your testimony?

A. I recommend the Commission approve the Company's request to adopt a seven year maximum contract term length for Wyoming QFs offering firm energy and capacity. This change will bring Wyoming's implementation in-line with the current economic and regulatory environment, and better balance PURPA's requirement for customer indifference against its requirement that QFs will have reasonable opportunities to attract capital from potential investors.

I further recommend that the clarifying changes the Company proposes for Schedules 37 and 38 be approved. These changes will improve the Company's process for PPA negotiations with QFs, and help to reduce QF complaints, which often include claims resulting from QFs' misunderstanding or misinterpreting the current versions of those schedules. Finally, I recommend that the items presented by Company witness Mr. MacNeil be adopted. The proposed refinements to the PDDRR methodology will improve the accuracy of avoided costs in Wyoming, and thereby reduce risks to customers. Using that improved PDDRR methodology to determine the Schedule 37 avoided costs will likewise improve the accuracy of those prices. Similarly, the change to Schedule 37's on-peak and off-peak definitions will more accurately reflect high price hours on the Company's system, and more fairly reflect when QFs should also receive higher prices.

Q. Does this conclude your rebuttal testimony?

A. Yes.