Docket No. 20000-___-EA-18
Witness: Mark P. Tourangeau

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Mark P. Tourangeau

November 2018

Q. Please state your name, business address, and present position with Rocky Mountain Power, a division of PacifiCorp ("Company").

A. My name is Mark P. Tourangeau. My business address is 1407 W. North Temple, Salt Lake City, Utah 84116. I am employed by Rocky Mountain Power as Vice President of Customer Solutions and Business Development.

<u>QUALIFICATIONS</u>

Q. Please briefly describe your education and business experience.

A. I received a Bachelor of Arts degree in Economics from the University of New Hampshire, and a Master of Arts in Economics from the University of New Mexico. I also am a Chartered Financial Analyst charter holder. I have been employed by the Company since 2017. Prior to that, I was employed by NextEra Energy, Inc. as Vice President Business Management and Vice President Trading Risk Management; and before that I worked at Morgan Stanley Commodities and Duke Energy.

Q. What are your responsibilities in your current position?

A. I am responsible for execution of Rocky Mountain Power's Commercial Strategy. I manage the commercial functions, including Commercial Services, Customer Solutions, Customer and Community Management, and Economic Development. I am also responsible for negotiating power purchase agreements ("PPA") with qualifying facilities under, and consistent with, the Public Utility Regulatory Policies Act of 1978 ("PURPA").

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have filed testimony with the Public Service Commission of Utah in Dockets No. 17-035-52 and No. 17-035-72. I also submitted direct testimony with the Wyoming

Public Service Commission ("Commission") in several recent qualifying facility ("QF") cases.

<u>PURPOSE AND SUMMARY OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. I support and present 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. The proposed modifications improve the implementation of PURPA Schedule 38 by:

1. Reducing the fixed price contract length for non-standard QF PPAs (Schedule 38 PPAs) and Firm Power Time of Delivery QF PPAs (Schedule 37). I will provide supporting evidence and discuss why a shorter term length for QF PPAs is fairer to customers, consistent with PURPA's customer indifference standard, and remains consistent with PURPA's requirement that QF developers have a reasonable opportunity to attract capital for their Wyoming projects. Specifically, the Company is requesting an order from the Commission to shorten the fixed price term for QF PPAs from 20 years to seven years for any QF that qualifies under Rocky Mountain Power's Schedules 37 and 38. This change in the fixed price term would also apply to any firm Schedule 37 or 38 QFs that re-apply for QF PPAs after expiration of their existing PPAs.

2. Clarifying the processes and procedures in the Company's Schedule 37 and Schedule 38 to ensure transparency in avoided cost pricing requests and PPA negotiation and execution procedures, including (i) clarifying language that providing a pro-forma PPA does not mean the QF is at the PPA negotiation

phase; (ii) clarifying language that the Company has the right to update pricing any time prior to execution and filing of the PPA with the Commission; (iii) adding specific tariff provisions that the QF commercial operation date ("COD")(or the delivery term of subsequent PPAs for existing QFs) must 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.

3. Clarifying certain aspects of the processes and procedures in the Company's Schedule 37 to ensure there is no confusion among potential QFs how their PPAs will be negotiated, including adding language so that QFs understand that after acquiring 10 MW of Firm Power resources under Schedule 37, pricing for QFs larger than 100 kilowatts ("kW") 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.

4. I will discuss the Company's proposals and how they will improve the contracting process for the benefit of our customers, prospective QFs, and the Company.

In addition to the proposed changes above, the Company also requests approval of the following items supported with direct testimony by Company witness Daniel J. MacNeil:

1. Refinements to the currently approved Partial Displacement Differential Revenue Requirement ("PDDRR") methodology used to calculate avoided

costs under Schedule 38, Avoided Cost Purchases from Non-Standard Qualifying Facilities.

2. Adoption of the same avoided cost methodology approved for Schedule 38 (including the proposed refinements within this application) to develop published pricing under Schedule 37, Avoided Cost Purchases from Qualifying Facilities.

3. Changes to the on-peak and off-peak definitions in Schedule 37 to better differentiate between periods of higher and lower avoided cost.

Q. How is your testimony organized?

A. First, I describe in detail the current status of operating QFs and those under development in Wyoming and in PacifiCorp's other service territories.

Then I discuss factors that demonstrate the current contract term of 20 years for QFs leads to poor economic outcomes, and violates a central principle of PURPA—the customer indifference standard. This is because 20-year QF contracts expose the Company's customers to significant risk because they are tied to resources that do not go through a rigorous planning process, like the integrated resource plan ("IRP"), which accounts for the interaction between generation, transmission and load on the Company's system. In addition, they are not chosen through a competitive process to ensure that only least-cost, least-risk resources are added when the IRP demonstrates a need. Further, these QF resources expose customers to additional significant potential costs due to the must-take provision in PURPA, which requires a utility to dispatch QFs regardless of economics even when cheaper options are available through economic dispatch or, in PacifiCorp's case, purchases from the Energy Imbalance

Market ("EIM").

Next, I discuss how a seven year contract term length still allows QF developers reasonable opportunities to develop renewable generation under PURPA in Wyoming. I describe executed transactions between developers and customers with shorter term PPA contracts—both in organized markets and with vertically integrated utilities, and for both market-based and PURPA contracts—and demonstrate that these shorter term contracts are able to attract capital at borrowing rates that support ongoing development. I also provide examples of other states that have implemented PURPA with shorter term fixed price contracts (as short as one or two years in some cases) based on the specific economic and regulatory environments in their jurisdictions, while still remaining consistent with PURPA's mandates.

Lastly, I discuss PURPA and how (a) this 40 year old law, from a different energy era, has achieved its purpose through a combination of its requirements, the evolution of electricity markets, federal and state tax incentive policies, and technological innovation; and (b) its implementation in the current energy era can be improved through the deference granted by the federal government to state regulators, especially in meeting the customer indifference principles that are a central part of the law.

<u>QF STATUS IN PACIFICORP'S SERVICE TERRITORY</u>

Q. Please give a high level overview of the Public Utility Regulatory Policies Act of 1978 ("PURPA").

A. Congress passed PURPA and it was signed into law in 1978 in response to the United

States' energy crisis.[1] PURPA's goal at the time was to promote renewable energy development and cogeneration technologies as alternatives to oil and other more expensive sources of fuel, with the commensurate goal of improving electricity distribution and reliability.

Two of the main requirements of PURPA are (i) electric utilities are obligated to purchase power produced by renewable or cogeneration energy qualifying small power producers, or "qualifying facilities" (QFs), which is referred to as the mandatory purchase, or must-take obligation;[2] and (ii) the price paid by utilities for such purchases must be "just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against qualifying cogenerators or qualifying small power producers."[3] This is known as the customer indifference principle.

PURPA is now a 40 year old law and the energy markets and technology have changed dramatically since 1978. The conditions that prompted the passage of PURPA no longer exist. Today, the United States is a net energy exporter, and rapid changes in renewables technology for solar and wind energy allow these technologies to compete on a levelized cost of energy basis with more traditional sources of electricity. However, the Company is still required to purchase energy from QFs under PURPA's original must take obligation, and purchase whatever power is delivered in every hour that it is available, even when less expensive options are available from the Company's own generation or through the California ISO's ("CAISO") EIM.

[1] 16 U.S.C. § 2601 et seq. (2012).
[2] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a) (2005).
[3] *Id.*

Q. What is the current status of QFs in the states served by PacifiCorp?

A. We have a large number of QFs in operation on our system, and many more under contract, in the QF pricing queue, and in the PacifiCorp Transmission generation interconnection queue as described below.[4]

The Company has 1,987 megawatts ("MW") of QF capacity in operation across six states, an additional 747 MW of capacity under contract but not yet in operation, and 3,756 MW in the pricing queue. **Table 1** shows the Company's QFs in operation and under contract (i.e., a signed PPA with a QF that has not yet reached commercial operation) within each state.

Table 1

	QFs In Operation (MW)	QFs Under Contract not yet in Operation (MW)	QFs in the Pricing Queue (MW)
Utah	1,001	174	441
Wyoming	398	458	1,518
Oregon	382	115	952
Other States	206	0	80
Total	**1,987**	**747**	**2,991**

The largest amount of capacity in the pricing queue is in Wyoming, with 24 QF projects consisting of 1,518 MW of capacity, and the second largest amount is in Oregon, with 17 QF projects consisting of 952 MW of capacity. In Wyoming, of the 24 QF projects, there are eight wind QFs with 596 MW of capacity and 13 solar QFs with 780 MW of capacity. **Table 2** provides a further break out by state:

[4] The QF pricing queue consists of QFs that have requested indicative avoided cost pricing based on the QF procedures outlined in the relevant state tariffs for large QFs (Schedule 38 in Wyoming); the PacifiCorp transmission interconnection queue is the list of generator interconnection applications maintained and studied by PacifiCorp Transmission, as governed by the FERC regulated PacifiCorp Open Access Transmission Tariff ("OATT").

Table 2

		MW by Technology			
	Wind	Solar	Other	Total
Wyoming	596	780	141	1,518
Oregon	0	952	0	952
Utah	80	300	61	441
Other States	0	80	0	80
Total	**676**	**2,112**	**202**	**2,991**

Q. Please discuss the situation with respect to out of state QFs seeking to interconnect or deliver onto PacifiCorp's system.

A. QFs located outside of the Company's service territory are seeking to exploit the arbitrage opportunities due to the favorable longer contract term lengths offered in Wyoming as compared to the states in which these facilities are located.[5] In Wyoming, of the 24 projects in the queue, five of the QF projects, totaling 400 MW of capacity, are located in Montana.

Q. In your opinion, why is it likely Montana-based QFs are seeking to obtain avoided cost pricing from PacifiCorp in Wyoming?

A. The state of Montana's contract term for QFs over three MWs was reduced from 25 years to 10 years in length in 2016 by the Montana Public Service Commission. The Commission also shortened the fixed price contract length to the initial five years of the contract.[6] If a QF has a contract over five years, the contract rate automatically resets after five years to the then applicable avoided cost rate for small QFs for the

[5] *In The Matter Of The Amended Joint Complaint Filing By Trireme Energy Development II; 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*, WPSC Docket No. 20000-505-EC-16; Record No. 14579.

[6] *See* Montana Public Service Commission Docket No. D2016.5.39 Order No. 7500c (July 21, 2017).

remaining term of the contract.[7] These Montana-based facilities seeking PPAs as Wyoming QFs likely chose to interconnect with or to transmit and sell power into PacifiCorp's Wyoming territory to take advantage of Wyoming's longer contract term and more attractive avoided cost pricing. Some of these projects only turned to Wyoming after litigation at the Montana Public Service Commission, in which they sought higher rates and longer terms from Northwestern Energy.[8] Notably, while the Company remains obligated under PURPA to purchase the output offered by these QFs, these projects do not produce the same degree of economic benefits for Wyoming because the related construction jobs, permanent jobs, and tax revenues will primarily flow to the states and communities in which the QFs are located. Without the changes the Company is requesting, it is likely that even more QFs located in neighboring states will recognize the arbitrage opportunities provided by Wyoming's longer maximum contract term, and potentially more favorable avoided cost pricing, and seek PPAs with the Company that will ultimately burden the Company's customers with the costs, while allowing a large portion of the economic benefits of these resources to accrue outside of Wyoming.

DIFFERENCES IN RESOURCES PROCURED BASED ON THE IRP AND QFS

Q. How does the Company evaluate the timing, amount and types of generation needed to provide least-cost, least-risk electric service for future customer load requirements?

A. PacifiCorp follows a rigorous, stakeholder focused integrated resource planning process to determine when, where, and what type(s) of generation to add to the

[7] *Id.*
[8] Montana Public Service Commission Docket No. D2016.12.103 Order No. 7535b (November 29, 2017).

Company's system. The IRP is a comprehensive decision support tool and road map for meeting the Company's objective of providing reliable and least-cost electric service to all customers while assessing many of the risks and uncertainties inherent in the electric utility business. The IRP is developed with public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, and other stakeholders. The key elements of the IRP include: determining the Company's resource need, focusing on the first 10 years of a 20-year planning period; establishing the preferred portfolio of supply-side and demand-side resources to meet this need; and developing an action plan that identifies the steps the Company will take during the next two to four years to implement the plan.

Q. How frequently is PacifiCorp's IRP updated?

A. PacifiCorp prepares its IRP biennially and files the results of the IRP with state utility commissions during each odd numbered year. For even-numbered years, the Company updates (and files) its preferred resource portfolio and action plan, as identified in the most recent IRP, by considering the most recent resource cost, load forecast, regulatory, and market information.

Q. How is the IRP developed?

A. The Company uses system modeling tools as part of its analytical framework to determine the long-run economic and operational performance of alternative resource portfolios. These models simulate the integration of new resource alternatives with the Company's existing assets, thereby informing the selection of a preferred portfolio, considered to be the most cost-effective resource mix after considering risk, supply reliability, uncertainty, and government energy resource policies.

The Company has historically targeted a 13 percent reserve margin of resources versus peak load, and the IRP process identifies the least cost portfolio of assets that meets this reserve margin while ensuring affordable, reliable supplies of electricity for PacifiCorp's retail customers. This process is made all the more difficult due to the uncertainty the Company has regarding new QF capacity that may be added to the Company's system during the IRP planning periods.

Q. Please describe the extent to which the Company is focusing its efforts on procuring renewable generation assets to serve retail customers.

A. PacifiCorp is committed to optimizing our existing generation while reducing the overall carbon intensity of our fleet over time. For several years, the Company's use of renewable energy to serve customers has steadily increased. In 2017, nearly one-third of the Company's electric generation capacity was from zero-fuel cost, zero-carbon emitting plants.

For example, the Company's recently approved Energy Vision 2020 project creates a cleaner energy future for customers while keeping energy bills affordable by leveraging federal production tax credits to provide a net cost savings to customers over the life of the projects.[9] In addition, the projects are expected to create hundreds of construction jobs and add millions in tax revenue to rural economies in Wyoming.

The Company is continually looking for opportunities to acquire renewable generation resources to meet needs identified through the IRP process using competitive solicitations designed to select resources that provide net economic benefits to customers. All of the resources acquired in this manner are integrated into

[9] *See generally, In the Matter of the Amended Application of Rocky Mountain Power for Certificates of Public Convenience and Necessity and Nontraditional Ratemaking for Wind and Transmission Facilities,* Wyo. P.S.C. Docket No. 20000-520-EA-17; Record No. 14781; (the Commission's order approving a stipulation in the Wyoming EV2020 proceeding was issued on October 8, 2018).

the Company's economic dispatch generation stack, meaning that, unlike QFs, they will only be dispatched when they are equal to or less expensive than the next available resource in the stack. This dispatch flexibility provides ongoing value to customers that is not available from QFs due to PURPA's out of date must take obligation.

Q. How does the IRP process compare to PURPA and the process that third-party developers use to site QFs on PacifiCorp's system?

A. Unlike the Company, QF developers are not required to consider the long-run impacts of their siting decisions on transmission, pricing, or dispatch. PacifiCorp is currently required to enter into 20-year fixed price contracts with QFs in Wyoming. In contrast, each of the Company's long-term generation resource decisions receive considerable scrutiny from regulators, customers, and other stakeholders. This prudency review ensures that given the information known at the time, the least-cost, least-risk decisions will be made with respect to new generation.

The process required for a QF to acquire a PPA with the Company can lead to QFs having significantly higher operational, price, and credit risks for the Company's customers compared to resource decisions that are guided by the IRP and procured via competitive solicitations. Shortening the fixed price contract term will help mitigate many of the risks that result from QF additions that fall outside the Company's typical approval process.

Q. What impact does PURPA's must-take obligation (barring emergency conditions) have on customers?

A. The must-take obligations of PURPA, where the Company is required to dispatch QFs 100 percent of the time (except in low load situations or emergency conditions), regardless of cost, has a negative impact on customers over time. Because of this must take requirement, out-of-economic-merit energy is being dispatched, the costs of which the Company's customers pay, rather than the normal course of dispatching less costly generation or taking advantage of low or even negative prices (where generators pay PacifiCorp to purchase their power) in the EIM. This negative pricing has been occurring when California produces more energy than it can consume during the solar peak—and is an outcome of what has been described for a number of years as the "duck curve". PacifiCorp's participation in the EIM has allowed the Company to arbitrage the duck curve, contributing to $136 million in savings for the Company's customers since the implementation of EIM in 2014.[10] During this period of market and technological changes in power generation and delivery, subjecting PacifiCorp's customers to long-term, static pricing compromises the Company's ability to provide least-cost, least-risk energy to our customers.

Q. What are the implications for the Company's customers from the differences discussed above between QF generation resources and the resources that the Company procures through the IRP process?

A. The Federal Energy Regulatory Commission ("FERC") has affirmed the need to ensure customer indifference to utility purchases of QF power, noting that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged

[10] Western Energy Imbalance Market, at About – Benefits, available at, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx (last accessed November 1, 2018).

alternatives".[11] FERC currently has an open docket to examine the implementation of the law through federal regulations in light of the aforementioned market and technological changes,[12] and of what some perceive are abuses of the law, including gaming of the one mile rule.[13] When weighing the risks presented by entering into 20-year QF contracts at avoided costs, where the resulting costs associated with these long-term contracts can be higher than the costs and risks associated with adding the next resource identified through the IRP process, combined with the costs and risks associated with the Company's "must-take" obligations to dispatch uneconomic power compared to what can be dispatched or purchased in the EIM, PacifiCorp's customers are not indifferent to 20-year fixed-price purchases by the Company of QF energy and capacity.

The Company acknowledges that the mandates of PURPA do not allow these risks to customers to be eliminated altogether, but PURPA does provide states with a wide degree of flexibility that allows them to implement the law in ways that better account for such risks based on the economic and regulatory circumstances within their jurisdictions. A reasonable solution to reduce these risks, which is well within the boundaries of PURPA's mandates and will bring Wyoming's PURPA implementation closer to the customer indifference balance the law requires, is to shorten the term for

[11] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at p. 62,080 (1995), overruled on other grounds, Cal. Pub. Util. Comm'n, 133 FERC ¶ 61,059 (2010).

[12] *See* Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000, Federal Energy Regulatory Commission.

[13] Utility Dive, September 17, 2017 "Renewables developers 'gaming' PURPA should force reforms, utilities tell Congress" (stating that, "While PURPA was always meant to compel utilities to purchase power from independent suppliers, critics argue that developers are increasingly "gaming" the law by splitting large-scale renewable developments into smaller portions to meet PURPA's size requirements — under 80 MW in vertically-integrated states and 20 MW in organized markets. By ensuring their facilities follow the "one-mile rule" separating QFs, developers can secure preferable contract rates for large amounts of capacity and ensure utilities will purchase the output.") (last accessed on October 16, 2018).

QF contracts to seven years. A seven-year term preserves development opportunities for QFs in Wyoming, but also reduces the overall risks associated with the Company entering into long-term, fixed-price PPAs with QFs.

CHANGES TO PURPA IMPLEMENTATION IN OTHER STATES

Q. Have other states made changes in PURPA implementation to account for changes in the economic and regulatory environments within their jurisdictions?

A. Yes. Several states have examined and re-examined their authority to implement PURPA in a manner that complies with the law in supporting the development of small generators while at the same time better protecting their retail electricity customers. As I mentioned above, the Montana Public Service Commission recently reduced the contract term for QFs over three MWs from 25 years to 10 years in length and also made changes resulting in lower avoided cost pricing.[14] Idaho also recently lowered the fixed price contract length to two years for QFs.[15] In 2017, Alabama approved forecasted energy and capacity rates fixed for a one-year term with an evergreen provision allowing QFs to sell power in future years at updated avoided cost rates.[16]

Also in 2017, the North Carolina legislature passed House Bill 589, which was subsequently signed into law. House Bill 589 shortened the QF fixed price contract length from 15 to 10 years, and lowered the maximum size of a QF that can take advantage of the 10 year contract length to one MW or less. Under that law, larger

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[14] *See* Montana Public Service Commission Docket No. D2016.5.39 Order No. 7500c (July 21, 2017).
[15] *Order on Reconsideration, In the Matter of Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements*, Case No. IPC-E-15-01, Order 33419 (November 5, 2015).
[16] *For approval of Rate CPE – Contract for Purchased Energy*, AL PSC re Alabama Power, Order, Docket No. U-5213, 2017 WL 9775573 at *4 (March 7, 2017) (recognizing that "reaching this balance between projected cost and actual cost has not occurred in many cases - leaving customers paying more to QFs than what was intended under PURPA.").

projects are now required to go through a competitive procurement process that will add another 2,660 MW of solar QF generation in North Carolina over a 45-month period.[17] North Carolina passed this law in response to recent challenges that its utilities face in dispatching new QF renewable generation within their balancing areas, as well as the impacts of large numbers of QFs on overall reliability and the operation of baseload resources.[18] For example, in large part due to the large amount of QF generation with inflexible dispatch on Duke Energy North Carolina's system, on July 9, 2018, Duke was forced to call a system emergency and curtailed approximately 24 solar generators for one hour, after first curtailing company-owned solar resources.[19]

In 2018, Colorado's Public Utilities Commission promulgated rules that set avoided costs for QF contracts via an auction mechanism: "A utility shall use a bid or an auction or a combination procedure to establish its avoided costs for facilities with a design capacity of greater than 100 KW. The utility is obligated to purchase capacity or energy from a qualifying facility only if the qualifying facility is awarded a contract under the bid or auction or combination process."[20]

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[17] This competitive process gives the utilities in North Carolina decision authority "to determine the location and allocated amount of the competitive procurement within their respective balancing authority areas, whether located inside or outside the geographic boundaries of the State, taking into consideration (i) the State's desire to foster diversification of siting of renewable energy resources throughout the State; (ii) the efficiency and reliability impacts of siting of additional renewable energy facilities in each public utility's service territory; and (iii) the potential for increased delivered cost to a public utility's customers as a result of siting additional renewable energy facilities in a public utility's service territory, including additional costs of ancillary services that may be imposed due to the operational or locational characteristics of a specific renewable energy resource technology, such as non-dispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase re-dispatch costs." NC Session Law 2017-192, House Bill 589 "Utilities Commission Fees and Charges" as ratified 4/5/2017.

[18] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Summary of Sam Holeman's Direct and Rebuttal Testimony, NCUC Docket No. E-100, Sub 148.

[19] *"Developers cry foul as Duke Energy briefly interrupts private solar-power purchases"*, Charlotte Business Journal, July 10, 2018.

[20] Code of Colorado Regulations, 4-CCR 723-3-3902(c), "Small Power Producers and Cogenerators".

Q. Please provide some examples of the impacts on QF development that other states have experienced with shorter fixed-price QF PPA terms.

A. As I mentioned above, Duke Energy implemented shorter-term contracts and other changes as a result of North Carolina's PURPA implementation, yet renewable development has continued apace. For example, as a result of the passage of North Carolina's HB 589, Duke Energy is in the process of procuring 2,660 MW of additional solar capacity in North Carolina over 45 months through *competitive solicitations* that will add to the existing 2,900 MW of solar capacity in the state. Each of these renewable sites has to be 80 MW or less in capacity, which is the same capacity size restriction placed on QFs by PURPA, essentially guaranteeing continued opportunities for QF developers that have projects that can bid competitively.

POTENTIAL IMPACTS OF SEVEN YEAR CONTRACT TERMS

Q. Do you believe a reduction in the contract term will result in a significant decrease in renewable and cogeneration resource development in Wyoming, contrary to the stated intentions of PURPA?

A. No. The Company expects renewable and cogeneration resource development to continue in Wyoming regardless of the change in fixed-price contract term. The goal of this filing is to make implementation of PURPA more fair to our customers to balance the Company's obligation to provide QFs reasonable opportunities to sell their output and customer indifference. Given the abundance of potential solar and wind resources in the state, the continued technological advances in renewables, and the vast amount of capital chasing renewable deals nationally, the Company does not expect QF development to slow appreciably. Also, in addition to seeking QF status for their projects under Schedule 38, PacifiCorp expects opportunities to continue for Wyoming renewable developers to bid their projects into solicitations for customers located in PacifiCorp's territories. Opportunities in the future for renewables to compete for projects that are solicited as a result of the Company's biennial IRP process are also likely.

Q. Will QFs have reasonable opportunities to attract capital from potential investors at a maximum fixed-price PPA term of seven years?

A. Yes. There has been a trend over the last five years towards shorter contract terms for renewable PPAs in general. Many of the corporate buyers who are contracting for renewables to meet sustainability and/or carbon neutrality goals are seeking contracts as short as seven years. These deals are getting done and are getting financed.

Owens Corning and Equinix each signed 12-year PPAs on NextEra Energy Resources' 250 MW Rush Springs wind farm in Grady, Oklahoma in 2016, splitting the capacity equally between them.[21] Salesforce signed a 15-year PPA in 2018 to purchase 80 MW of the output of EDP Renewables' 205 MW Bright Stalk wind farm in McLean County, Illinois. At the same time, EDP Renewables also announced a 50 MW, 15-year PPA with an unidentified energy company for part of its 200 MW Broadlands wind project in Douglas County, Illinois.[22] Between 2015 and year-to-date 2018, at least 46 PPAs have been signed in the United States for wind and solar facilities that are over 20 MW that have terms ranging from three years to 15 years.[23]

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[21] S&P Global Market Intelligence, accessed October 12, 2018.
[22] Renewables Now, September 4, 2018, "EDPR backs 200 MW wind project in Illinois with new PPA", available at https://renewablesnow.com/news/edpr-backs-200-mw-wind-project-in-illinois-with-new-ppa-625570/, (last accessed November 1, 2018).
[23] S&P Global Market Intelligence, accessed October 12, 2018.

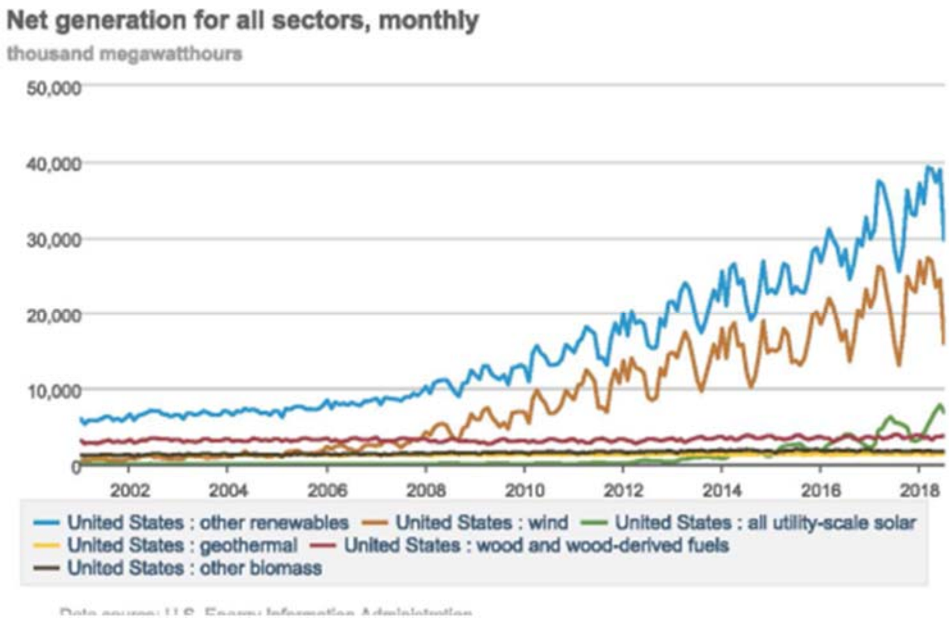
This is almost 4,500 MW of contracted renewable capacity since 2015 with PPAs of 15 years or less.

Also, there have been utility-scale renewable resources built that are secured by "bank hedges" instead of PPAs. Bank hedges are fixed for float financial swaps that developers enter into with banks or insurance companies to hedge the prices they receive for some or all of their renewable electricity generation. These introduce additional volumetric and locational basis risk for the project owners, but the deals are still being done. For example, Pattern Energy's Panhandle Wind 2 project, a 182 MW wind project in Carson County, Texas, does not have a PPA contract, but instead was built and financed using a 13-year, fixed-for-float swap with Morgan Stanley that only covers 80 percent of the expected output of the facility.[24]

Even with these trends towards shorter contract lengths for QF and non-QF projects, and bank hedges for non-QF projects, the growth in renewables capacity has outpaced the growth of other types of generation for a number of years in the United States. Figure 2 below shows Energy Information Agency data on sales from renewable facilities since 2002.

[24] *See*, Pattern Energy, at https://patternenergy.com/learn/portfolio/panhandle-wind-2 (last accessed November 1, 2018).

Figure 2



In 2017, 55 percent of the 21 gigawatts ("GW") of new capacity additions in the United States were renewables, and renewables have comprised the majority of all new capacity additions over each of the last four years.[25] Between 2008 and 2017 over 103 GW of renewables capacity was added in the United States.[26] Of this 103 GW of capacity additions, 14 GW have been certified as QFs—that's 14,000 MW of new QF capacity. The majority of these QF additions have been in states that do not participate in Regional Transmission Organizations ("RTOs"), like Utah and Wyoming, because the Energy Policy Act of 2005 exempted utilities in states that participate in RTOs from the majority of their PURPA obligations.[27]

[25] US Energy Information Administration, Monthly Energy Review (October 26, 2018), at Table 10.1 "Renewable Energy Production and Consumption by Source," monthly view, available at https://www.eia.gov/totalenergy/data/browser/?tbl=T10.01#/?f=M (last accessed November 1, 2018).
[26] *Id.*
[27] Energy Policy Act of 2005, 42 USC 15801.

Figure 3

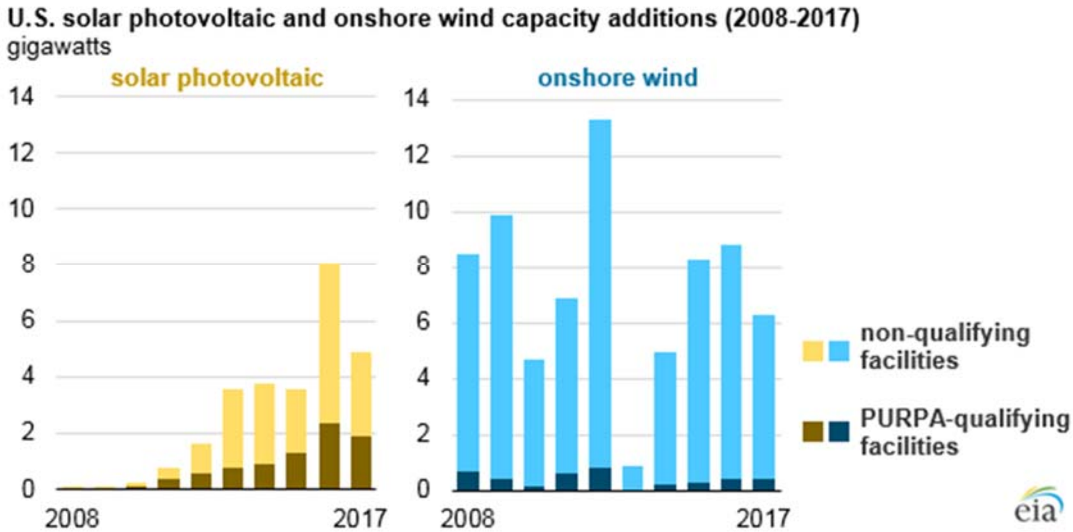


Figure 3 shows the comparison between QF and non-QF solar and onshore wind capacity additions over the last 10 years, and even as the trend towards shorter contracts has continued, QF capacity additions, especially solar additions, have grown substantially. Figure 4 shows the comparison between QF and non-QF solar and on-shore wind additions during 2008–2017 for the top 10 states in overall capacity additions during that time.[28]

[28] US Energy Information Administration, *Today in Energy*, “PURPA-qualifying capacity increases, but it's still a small portion of added renewables", (August 16, 2018), available at https://www.eia.gov/todayinenergy/detail.php?id=36912, (last accessed November 1, 2018).

Figure 4

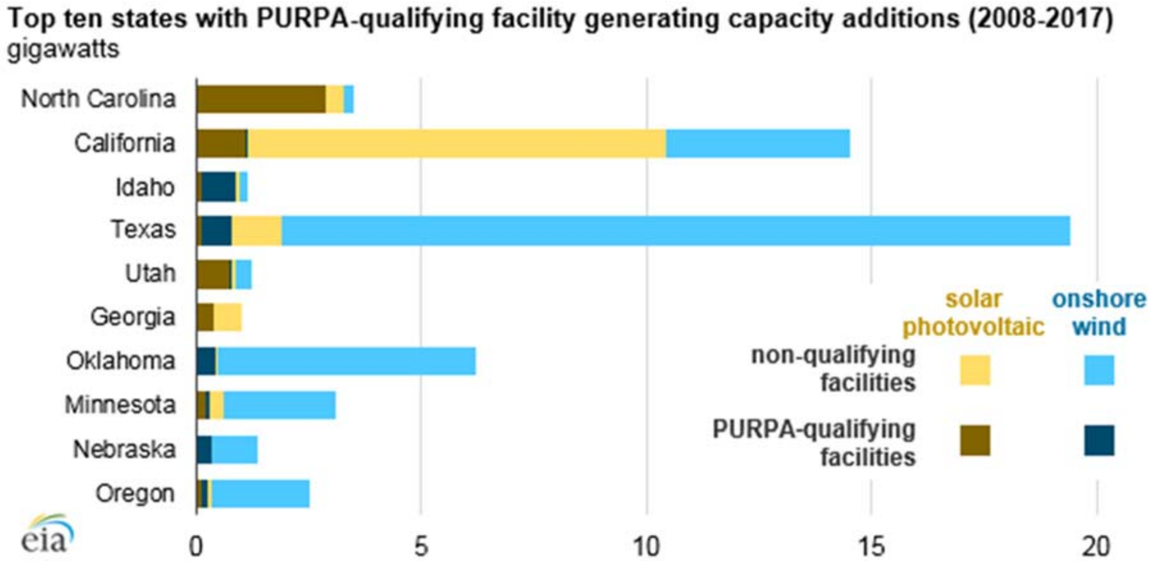


Figure 4 demonstrates that California, most of Texas, Oklahoma, Minnesota, and Nebraska all participate in RTOs, and have significantly higher non-QF capacity additions than all other states except Oregon.[29]

Q. For non-RTO utilities, is PURPA's purchase obligation still important to the ongoing development of new renewable resources?

A. To some extent, yes. Capacity additions from QFs have been strong in non-RTO states, indicating that PURPA's must purchase obligation continues to be an important element driving a portion of the renewable development in those states. However, technological and market forces have rendered PURPA's renewable goals less important than they were when it was enacted in 1978. Indeed, with over 103 GW of renewables capacity added in the last 10 years, and continued strong growth in the market as individual customers, corporations, municipalities, universities, and utilities

[29] *Id.*

all seek to increase their purchases of renewable generation,[30] these large additions of renewable capacity are likely to continue for quite some time. In other words, while PURPA is one important tool for the further development of renewable energy, there are many other new mechanisms that help ensure continued opportunities for cost effective renewable projects sited in the right locations to increase renewable penetration in non-RTO states like Wyoming. The re-balancing of risks the Company proposes here helps account for these newer renewable development mechanisms, and is necessary to meet the customer indifference standard, prevent the transfer of unnecessary risks from QF developers to PacifiCorp's customers, and will not unreasonably stifle opportunities for renewable development in Wyoming, whether through PURPA or other means.

Q. Does PURPA require the Company to offer terms to QFs that ensure QFs will obtain favorable financing, and will a change to a seven-year fixed-price contract ensure that project financing will not occur?

A. No. PURPA does not require utilities to offer terms to QFs that enable them to achieve the most favorable financing, though the Company expects QFs will make this argument in an attempt to counter the risk re-balancing the Company seeks. The argument does not hold up under scrutiny. PURPA requires that "a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors."[31] "Reasonable opportunities" cannot and does not

[30] One example of the phenomenon is RE 100, RE 100 is a global initiative that involves more than 100 businesses seeking to procure 100 percent renewable energy. This collaborative includes corporations such as IKEA, Bank of America, Coca Cola, Citi, eBay, Facebook, Google, HP, and Microsoft. More information available at http://there100.org/.
[31] *Windham Solar*, 157 FERC 61.134 at P. 8.

mean an obligation to offer a contract term that ensures the best possible opportunity for QFs to get the lowest possible borrowing rates or highest levels of leverage possible. Doing so would transfer most of the risk of the investment from the QF developers, who would then benefit from outsized returns, to the utility's customers' detriment, and that was never the purpose of PURPA. A "reasonable opportunit[y] to attract capital from potential investors"[32] does not equate to a requirement to offer contracts of a specific tenor, it means that QF developers should be able to compete for capital on a level playing field with other renewable projects. As my testimony makes clear, the contract term lengths needed to provide this level of opportunity have shifted over time, and a corresponding adjustment in Wyoming is entirely justified and consistent with PURPA.

Q. Will a change to a seven-year fixed-price contract for QFs unreasonably limit PURPA facilities' access to financing?

A. No. Given the current financing environment, a seven-year fixed-price contract term allows QFs to compete for capital on a level playing field. As noted, many transactions for renewable resources have been consummated in the last three years at PPA terms of 15 years or less, in all likelihood each of these secured some level of debt financing, tax equity financing, or a combination of both.

Q. Please discuss other financing options that are available to QFs, even with shorter term contracts.

A. Many QF developers also develop non-QF facilities in deregulated markets and end up refinancing project-level debt with syndicated funding that includes both QF and non-

[32] *Windham Solar LLC and Allco Finance Ltd.("Windham Solar")* 157 FERC P 61,134 (2016), 2016 WL 6921612, at ¶8.

QF projects in the same syndication, or raise debt capital to fund additional growth. These are large, sophisticated deals that often replace or supplement project-level debt and provide additional capital for developers to grow their portfolios. Three different examples of these types of capital raises were recently announced by sPower and Cypress Creek Renewables Power (both QF developers) on their websites that when combined, total almost $1.37 billion in financings.[33, 34, 35]

These examples demonstrate the robust financing options available to QF developers in the capital markets across many different debt and equity options, both domestically and internationally. In an investor presentation issued by Cypress Creek Renewables, in 2016 titled “Solar Overview and Lending Opportunities”, Cypress Creek touted its access to PPAs in regulated markets with utilities that have “massive balance sheets serving as a de facto credit tenant” and that “protections for independent

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[33] 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).

[34] On September 20, 2018 sPower issued a press release stating they recently closed a $498.7 million investment grade, private placement financing. sPower described this as among the first ever widely-distributed back-leverage bond financings on tax equity partnerships. The portfolio is comprised of four previously financed tax equity partnerships with four leading financial investors.” sPower goes on further to state “The proceeds from this issuance refinanced approximately $425 million of medium-term bank loans, lengthening tenor to a fully-amortizing 23.5-year facility and eliminating the refinancing risk associated with previous bank loans. Incremental proceeds net of the bank loan refinancing will be used to fund sPower’s continued development of additional renewable generating facilities. The offering was significantly oversubscribed by a diverse group of leading US private placement investors.” *Id.*

[35] On July 26, 2017, Cypress Creek Renewables Power issued a press release stating they recently closed a $450 million debt facility led by Singapore-based investment company Temasek. In the press release, Matt McGovern, Cypress Creek Renewables CEO, said: “This agreement accelerates our mission to put as much solar in the ground as soon as possible. We are excited at the opportunity to further build the business with support from Temasek and our other partners.” Temasek is an investment company headquartered in Singapore. Temasek owns a $275 billion (US$197b) portfolio as of March 31, 2017, mainly in Singapore and the rest of Asia. Available at, http://www.prweb.com/releases/2017/07/prweb14536216.htm, (last accessed 10/11/2018).

power producers are provided under both federal and state regulatory frameworks."[36] In the same presentation, Cypress Creek stated its business model focuses on "utility scale ground mount projects primarily 2-80 MW in capacity in multiple US states, with a multi-pronged development strategy: QF standard offer PPAs, bilateral PPAs, retail markets, and community solar."[37]

In the same presentation, Cypress Creek also noted that it can raise capital from a United States Department of Agriculture ("USDA") Rural Development program, which at that time had experienced "Zero" losses on utility scale solar and "Zero" delinquencies on utility scale solar. At the time Cypress Creek published the presentation, the USDA renewables portfolio had in excess of $200 million outstanding and Cypress Creek stated it would likely double in six months.[38]

The USDA program is called the Rural Energy for America Program ("REAP") and it makes renewable energy systems and energy efficiency improvement loans and grants available.[39] In 2016, the program made approximately $300 million in combination grants and loan guarantees available for utility scale solar in rural areas of the United States.[40] The loan guarantees are for loans of up to $25 million, which provides QF developers in rural areas yet another competitive source of capital. The

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[36] *See*, *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities-2016*, McConnell Cross Exam Exhibit No. 4, North Carolina Utilities Commission, Docket No. E-100 Sub 148, available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=5679ce67-9245-4d03-b20e-1c7b3997b4a4 (last accessed November 1, 2018).
[37] *Id.*
[38] *Id.*
[39] This program was authorized by Title IX of the Agricultural Act of 2014, ("2014 Farm Bill"); available at USDA website, https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency, (last accessed October 11, 2018).
[40] *See*, USDA Energy Investment Report, available at https://www.usda.gov/energy/maps/report.htm, (last accessed October 11, 2018).

funds may be used for the purchase, installation and construction of renewable energy systems including large wind generation and large solar generation.[41] The loan guarantees have a maximum term of 15 years, or useful life, for machinery and equipment, a maximum term of seven years for capital loans, and a maximum term of 30 years for combined real estate and equipment loans.[42]

So while many QF developers testify in PURPA dockets in front of various state commissions that they are small scale and can only secure financing with PPA contract lengths that are 20 years or longer, in the capital markets many operate as large, sophisticated borrowers competing for billions of dollars in debt, sponsor equity or tax equity capital across a wide range of private and public, domestic and international sources—where they tout their ability to lean on the "massive" balance sheets of regulated utilities to provide high quality credit support—essentially by transferring all risks onto the utilities' customers, thus providing investors with nearly risk-free investments.

Q. Are there risks that these pools of capital will dry up for the QF developers in the future?

A. Absent exogenous shocks to the economy that could affect the robustness of the renewables capital markets, there is confidence that this segment will not only sustain its current levels, but will experience considerable growth in the future. An article from Bloomberg news published on April 19, 2018, details how even though base interest rates are rising, spreads for solar transactions are tightening as more and more lenders,

[41] Rural Energy for America Program Renewable Energy & Energy Efficiency brochure, available at https://www.rd.usda.gov/files/RD_FactSheet_RBS_REAP_RE_EE.pdf, (last accessed October 11, 2018).
[42] *Id.*

especially from Asian banks, seek stable returns.[43] "There is more money chasing this market than ever before," according to Mike Pepe, New York-based managing partner of broker-dealer GrandView Capital Markets LLC. "Many invest in solar even though the yield is low because they perceive that they won't lose their principal."[44] In this same article, Richard Matsui, the chief executive officer at KWh Analytics, a solar risk-management firm in San Francisco stated that this favorable debt pricing has muted "what should otherwise be a punishing rate increase" for the solar industry.[45]

On June 19, 2018, the American Council on Renewable Energy ("ACORE") released the results of a survey it performed with leading financial institutions titled "The Future of U.S. Renewable Energy Investment."[46] ACORE was founded in 2001 and is a 501(c)(3) nonprofit that brings together hundreds of organizations across finance, policy and technology to promote the transition to a renewable energy economy.[47] The online, anonymous survey, which was performed by ACORE in April 2018 with investors in renewable energy projects and technologies, paints an incredibly optimistic picture of capital formation for renewables in the United States. Key survey highlights include:

- "Over the next three years, investor confidence in the U.S. renewable energy sector is expected to remain high, with an average confidence level of

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[43] "Banks are Sweetening Their Terms for Solar as Confidence Rises", Bloomberg News, 4/19/2018.
[44] *Id.* at P. 3.
[45] *Id.* at P. 4.
[46] The American Council on Renewable Energy (ACORE), "The Future of U.S. Renewable Energy Investment", June 19, 2018.
[47] American Council on Renewable Energy, available at https://acore.org/what-we-do/, (last accessed on 10/11/2018).

84/100."[48]

- "Two-thirds of respondents plan to increase their investments in U.S. renewables by more than 5% in 2018 compared with 2017, and half plan to increase their investments by more than 10%."[49]
- "Total sector projections to 2030: When considering ideal policy and market scenarios, 70% of respondents indicated that cumulative private investment in U.S. renewable energy could reach $500 billion between 2018-2030, while 26% projected it could reach $1 trillion"[50]

The respondents paint a bullish picture for renewables capital formation growth, and financial markets consistently show their ability to invent and adapt to change in underlying market dynamics. Based on both actual results over the last few years, and the very optimistic outlook for the future, QF developers should have no concerns that they will be prevented from attracting capital from a very deep pool of public, private, domestic, and international investors based on the Company's recommendation of a seven-year term length for fixed-price PPAs in Wyoming.

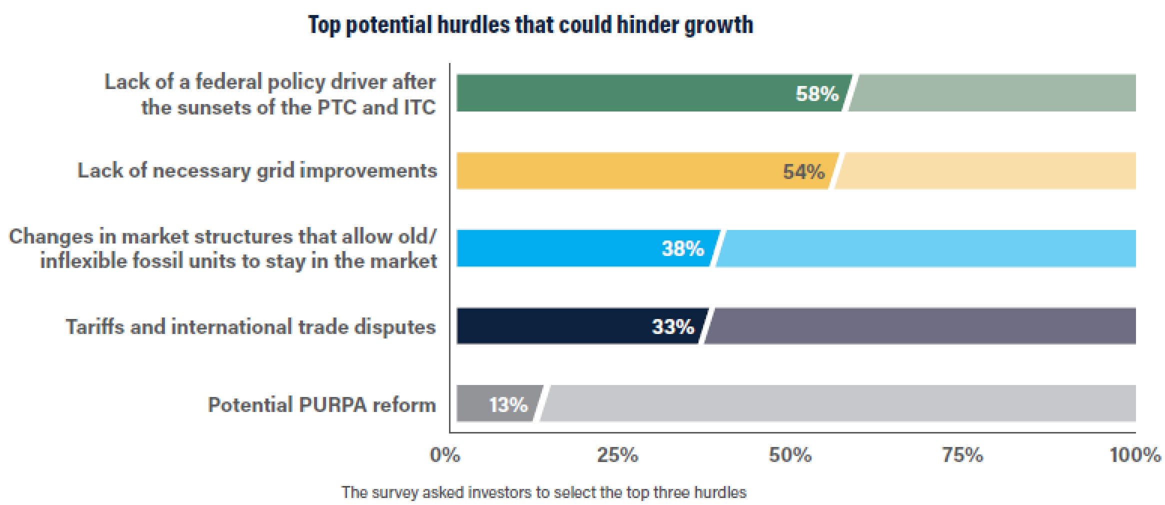
Q. What other insights did the Company glean from ACORE?

A. Another part of the ACORE survey asked the respondents to assess hurdles that could hinder renewables growth in the future. Overwhelmingly, the respondents rated potential PURPA reform as the lowest hurdle that could hinder growth. So while the QF developers may be motivated to present the risk re-balancing that the Company seeks as damaging to their industry, their investors see this type of reform as a very low

[48] The American Council on Renewable Energy (ACORE), "The Future of U.S. Renewable Energy Investment", June 19, 2018.
[49] *Id.* at P. 3.
[50] *Id.* at p. 3.

risk to future growth, well below the four other drivers, shown in Figure 5.

Figure 5



Q. Why should the Commission act now to modify the fixed price term for QF PPAs?

A. The Commission's Order in Docket No. 20000-481-EA-15 directed all parties to form a collaborative to achieve compromises with respect to opposing positions presented in that docket. While we were able to arrive at some compromises with respect to Schedule 37 through this effort, all of the Company's recommendations for changes to Schedule 38 were rejected, and the QF developers offered no alternatives. This failed effort and the increasing need to improve Wyoming's implementation of PURPA are why the Company is filing this application, and the Commission should act to approve the application and modify the fixed term now.

Q. Why is this the right time for the Commission to improve the implementation of PURPA in Wyoming?

A. We have seen increased QF activity to exploit arbitrage opportunities based on Wyoming Schedule 38 avoided cost pricing and the 20-year term, which is longer than in neighboring states, for sites both within and outside of Wyoming. During this same period, the Company has been able to take advantage of extremely competitive pricing for renewables, as installed costs continue to drop. The Company's acquisition of renewables outside of PURPA is the result of thorough analysis of the costs and benefits to our customers based on both price and location, and, unlike PURPA where customers merely break even, the Company must demonstrate that the acquisition is needed.

The market for renewables and their financing has changed, and Wyoming's 20-year fixed-price contracts for QFs no longer reflects the current reality. Maintaining the status quo places an unfair burden on our customers. QF developers are currently taking advantage of the status quo to de-risk their transactions by transferring the bulk of those risks to customers. As demonstrated above, some even tout the benefits of this risk shifting in presentations to their investors. Approval of the Company's request to set the maximum term to seven years recognizes the changes in the market and re-balances this risk. It affirms the Company's PURPA must-purchase obligation based on a term that allows QFs reasonable opportunities to access capital, while taking some of the risk burden off of the Company's customers—thereby maintaining the customer indifference principle.

Q. Please explain the changes the Company is requesting to the procedures outlined in Schedule 38.

A. The Company is requesting the following changes to Schedule 38 to ensure transparency in avoided cost pricing requests and in PPA negotiation and execution procedures: (i) clarifying language to state clearly that providing a pro-forma PPA does not mean the QF is at the PPA negotiation phase; (ii) clarifying language to state that RMP has the right to update pricing any time prior to execution and filing of the PPA with the Commission; (iii) adding specific tariff provisions stating that QF COD (or the start of the delivery term of subsequent PPAs for existing QFs) must not exceed 30 months from the PPA execution date and that QFs must provide project development security within 30 days of its PPA being filed with the Commission.

Q. How will these changes improve the QF approval process and therefore benefit customers, prospective QFs, and the Company?

A. These changes will improve the process by providing more definitive guidance for QF developers and the Company with respect to Schedule 38 indicative avoided cost price requests, timing for when PPA contract negotiations can begin, and the frequency with which the Company can provide avoided cost updates prior to contract execution. These clarifications will remove some of the misinterpretations of Schedule 38 that QF developers currently make, thereby eliminating wasted time and effort by developers and the Company in the Schedule 38 QF contracting process. This will also help eliminate disputes that sometimes rise to the level of Commission complaints, which reduces costs and administrative burden for all parties involved.

It is extremely important that the Generator Interconnection process that a QF must follow with PacifiCorp Transmission be separate from the Schedule 38 contracting process, due to the standards of conduct mandated by FERC. The interconnection process can be lengthy and should be started well before the contract process. An additional change to the Schedule 38 procedures makes clearer the requirement that a QF developer must be able to demonstrate their ability to reach their stated COD date in all respects, including interconnecting their project to PacifiCorp's transmission system. The provision of project development security shortly after contract execution helps to balance the risks associated with QFs timely achieving their stated CODs. Another change confirms the Commission's desire, as stated in its Trireme deliberations, that the avoided cost pricing that is in effect when a Legally Enforceable Obligation is established between the Company and a QF is the most recent pricing possible in order to meet the PURPA customer indifference principle.[51] Related to this concept, will be to codify what is the Company's existing practice, that the QF COD must not be more than 30 months from PPA execution date. This requirement protects ratepayers from bearing avoided cost prices that are 'stale', and no longer reflect the true avoided cost price for energy and capacity for the Company at the time the QF goes into operations. By stating the Company's existing practice explicitly in the tariff, the change will avoid future disputes with QFs seeking pricing for projects that are years away from being able to provide energy and capacity.

Q. Please explain the changes the Company is requesting to the procedures outlined in Schedule 37.

A. Aside from the changes that Company witness Mr. MacNeil discusses in his testimony, the Company is proposing changes to state its current practices with prospective firm QFs under Schedule 37 more explicitly. Specifically, the Company proposes the following: (a) additional language making it clear that when the 10 MW cap for firm

[51] *In The Matter Of The Amended Joint Complaint Filing By Trireme Energy Development II; 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*, Wyo. P.S.C. Docket No. 20000-505-EC-16; Record No. 14579, Commission Deliberations July 3, 2018.

pricing is reached, avoided cost pricing for subsequent QFs larger than 100 kW will be modelled in accordance with the methodology used for Schedule 38 QFs; (b) additional language is also proposed for Schedule 37 to clarify the Company's existing practice, which is that PPAs will be negotiated in a manner consistent with the non-pricing related procedures in Schedule 38. The latter change will therefore make the improvements I discuss above with respect to Schedule 38 applicable to the negotiation of Schedule 37 PPAs too.

Q. Can you please summarize your recommendations?

A. Yes. 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. Utilizing 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 direct testimony?

A. Yes.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED CONTRACT TERM OF PURPA POWER PURCHASE AGREEMENTS WITH QUALIFYING FACILITIES	)	DOCKET NO. 20000-___-EA-18 (RECORD NO. _____)

AFFIDAVIT, OATH AND VERIFICATION

Mark Tourangeau (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Vice President of Customer Solutions and Business Development for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his/her official capacity as Vice President of Customer Solutions and Business Development.

Further Affiant Sayeth Not.
Dated this 1st day of November, 2018

Mark Tourangeau
Vice President of Customer Solutions and Business Development
1407 W. North Temple, Suite 310
Salt Lake City, UT 84116

STATE OF Utah)
) SS:
COUNTY OF Salt Lake)

The foregoing was acknowledged before me by Mark Tourangeau on this 1 day of November, 2018. Witness my hand and official seal.

Notary Public

My Commission Expires: 10·19·19

LORI HUGHES
NOTARY PUBLIC -STATE OF UTAH
My Comm. Exp 10/19/2019
Commission # 685472