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Comments Concerning Qualifying Facility Rates under the Public Utility Regulatory Policies Act of 1978 (PURPA)

Comments prepared for the Federal Energy Regulatory Commission (FERC)

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As researchers at Resources for the Future (RFF), we are pleased to share the following comments to the Federal Regulatory Energy Regulatory Commission (FERC) on the Notice of Proposed Rulemaking (NOPR) for Qualifying Facility Rates and Requirements under the Public Utility Regulatory Policies Act of 1978 (PURPA).

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Introduction

Section 210 of the Public Utilities Regulatory Policies Act (16 U.S.C. 824a–3) provides a mechanism for small renewable generators (and combined heat and power facilities) owned by independent entities to find markets for their power by requiring local distribution utilities to purchase that power at prices equal to their avoided cost of producing or obtaining that power from other providers. The intent is to encourage the development of renewable sources without putting an undue cost burden on rate payers. Only power that can be profitably produced for prices at or below the utility's avoided cost will be engaged. The policy grants states a great deal of latitude in the method used to determine avoided cost and it has been particularly effective at driving investment in renewables, largely wind and increasingly solar, in states that do not participate in competitive markets. Originally passed in 1978, PURPA was amended as a part of the Energy Policy Act of 2005 as growing market opportunities for moderately sized renewables projects, those between 20 and 80 MW, suggested that the law was no longer necessary for such projects that also had access to competitive wholesale markets.

Throughout the history of PURPA implementation there have been concerns raised about the mechanisms used to determine the avoided cost rates paid to qualified facilities being overly generous. For example, as states developed their policies to implement electricity market restructuring and competitive markets in the late 1980's and early 1990s, high priced PURPA contracts were often deemed vulnerable to being underwater as a result of lower retail electricity prices expected to arise with the introduction of retail competition.[1] Modifications to PURPA included in the Energy Policy Act of 2005 helped to address some of these concerns. Nevertheless, recent declines in power prices across the country have again raised the concern that rates under PURPA create a burden on ratepayers.

On September 19, 2019, the Federal Energy Regulatory Commission, the agency responsible for writing the regulations to implement provisions of PURPA, issued a Notice of Proposed Rulemaking (NOPR) to modify several of the features of PURPA, including: (i) rates, (ii) purchase obligations, (iii) the rule for determining a single qualifying facility, (iv) commercial viability, and (v) self-certification. In these comments, we focus on the portion of the NOPR that addresses appropriate methods for setting rates offered to qualifying facilities for their power and, specifically, on how those provisions

[1] See Brennan, T. J. & Boyd, J. (1997). "Stranded Costs, Takings, and the Law and Economics of Implicit Contracts." *Journal of Regulatory Economics*. 11(1): 41–54.

interact with markets for project finance required for development of these new renewable generators.

Qualifying Facility Rates

The NOPR describes three prospective changes that states may make with respect to the rates paid to qualifying facilities (QFs). The first is to allow states to require that QFs receive "as-available" rates for energy, but not for capacity, rather than fixed rates over the life of the contract. The NOPR further specifies that as-available rates could be set (i) by locational marginal prices (LMPs) for a QF selling to a utility within an organized wholesale power market and (ii) by either liquid market hubs or natural gas prices and heat rates for a QF selling to a utility outside an organized wholesale power market. The second change would permit states to set fixed energy rates using forecasted prices at the QF's time of delivery—known as a forward price curve. The third change would allow states to set rates for energy and capacity through competitive solicitations. With the aim of PURPA to encourage and enable power production from small power production facilities at a just and reasonable cost, we believe the second and third proposed changes together could sufficiently address the commission's concerns about existing price setting mechanisms and be consistent with the law's objective, while the first would not.

Concern About Avoided Costs Under PURPA

QFs currently have the option of receiving contracted fixed rates equal to the avoided cost of the utility that is administratively determined prior to the start of the contract. This advanced price setting mechanism raises the possibility that the fixed rates will be significantly above, or below, market prices at the time of delivery. While the presumption has been that these deviations would roughly "balance out" over the life of the contract, the NOPR references a record finding that overpayments to QFs have prevailed as energy prices have declined in recent years. With this background, the commission has proposed that states be able to require that QFs receive variable, rather than fixed energy rates, equal to the price of electricity at the time and location of ultimate delivery of the power.

As the concern of QF payments not exceeding a utility's incremental cost (referred to as the avoided cost) is central to PURPA, the possibility of a divergence requires thorough consideration. With respect to QF rates and avoided costs, there are three separate issues, which we will consider in turn.

First, *average* wholesale power prices have certainly decreased over the past decade, from a median wholesale power market price of approximately $55/MWh in 2008 to $32/MWh in 2018 (in 2018$).[2] This decline has overwhelmingly been the result of reduced natural gas prices. Across independent system operator (ISO) markets, the effect of lower natural gas prices has been to decrease wholesale power prices between $7/MWh and $53/MWh from 2008 to 2017 (in 2017$). In contrast, additions of wind and solar capacity have caused an average reduction of $1.3/MWh over that period.[3] Annual average wholesale power prices reached their recent minimum of $25/MWh in 2016 and have increased since then, in parallel with a similar increase in natural gas prices. According to the US Energy Information Administration (EIA), Henry Hub natural gas prices are expected to rise further in the coming years, from approximately $3/MMBtu in 2018 to $3.75/MMBtu in 2030 (in 2018$),[4] which would raise average wholesale power prices wherever they are determined by natural gas prices. As such, while fixed prices determined 5-10 years ago would likely exceed current average market prices, that may not be true for fixed prices determined either more recently or in the future.

Second, because avoided costs should reflect the time and location of power delivery, average wholesale power prices are not a satisfactory benchmark. Wind and solar QFs will likely deliver power at times and places that have different than average prices. In most ISOs, the energy value of wind ranges from 60 percent to 80 percent of average wholesale energy values due to location (transmission constraints reducing energy value at wind nodes) and timing (wind generating at less valuable times of the day or year). Further, there is a negative correlation, albeit not a very strong one, between this value factor and the amount of wind generation in an ISO.[5] For solar, the case is different. When there is relatively little solar generation in a region, solar facilities usually receive above-average pricing due to the coincidence of their generation with peak loads. However, as more solar is added, the increase in midday power supply reduces prices that solar facilities receive. Indeed, this has been the experience in California, where the value factor of solar decreased from 125 percent in 2012 to 79 percent in 2017 as the amount of solar generation increased from 2 percent to 15 percent, respectively.[6] These price dynamics suggest the use of forward curves in setting contract

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[2] Wiser, R. (2019). "The Impacts of Variable Renewable Energy on Wholesale Power Prices: Implications for the Merchant Value of Wind and Solar." Lawrence Berkeley National Laboratory (LBNL). Berkeley, CA.
[3] Mills, A. et al. (2019). "Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017." Lawrence Berkeley National Laboratory (LBNL). Berkeley, CA.
[4] US Energy Information Administration. (2019). *Annual Energy Outlook 2019*.
[5] Wiser, R. (2019). "The Impacts of Variable Renewable Energy on Wholesale Power Prices: Implications for the Merchant Value of Wind and Solar." Lawrence Berkeley National Laboratory (LBNL). Berkeley, CA.
[6] Bolinger, M., & Seel, J. (2018). "Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition." Lawrence Berkeley National Laboratory (LBNL). Berkeley, CA.

prices, as the commission has proposed. We will discuss forward curves further in the final sections of the comments.

Third, the NOPR expresses a concern that fixed rates for QFs may persist in exceeding avoided costs due to the "continuing general decline in the cost of both wind and solar generation." However, there is not a consensus view that wind and solar generation costs will continue to decline. Future declines in wind and solar capital costs are projected to be relatively modest and will be offset to some extent by declining federal tax credits. In the Annual Energy Outlook 2019, the average levelized cost of electricity (LCOE) for wind actually rises between 2021 and 2040 (from $37/MWh to $44/MWh, in 2018$), and the average LCOE of solar remains constant at $40/MWh (in 2018$).[7, 8]

Irrespective of the trends in wind and solar LCOE, the cost of wind and solar generation is not the utility's avoided cost and therefore not the appropriate basis for setting rates for QFs. A utility's avoided cost is equal to the price of power at a particular time and location—in a competitive market—as described elsewhere in the NOPR. Potentially lower future costs of wind and solar would not constitute a benchmark for QF pricing. Instead, lower future costs of wind and solar would increase the amount of wind and solar capacity installed in a particular region, which would decrease market prices of energy and thus the avoided costs of wind and particularly solar as described above. For this reason, forward curves—accounting for any expected declines in cost and increases in capacity—would be useful in setting QF contract prices. Additionally, the dynamics of wind and solar capacity and avoided costs suggest a limited role for competitive solicitations, which we will also discuss in the final sections of the comments.

Fixed Rates Are Needed for Solar and Wind Qualifying Facilities

To support the commission's proposal permitting states to require that QFs receive variable energy rates, the NOPR contends that the ability for QFs to obtain financing would not be materially affected by a change to variable energy rates so long as capacity rates remained fixed. For wind and solar, which have intermittent generation, capacity value represents a small proportion of electricity value. In 2018, the average wholesale value of wind across ISOs was $22/MWh, of which $1/MWh was for capacity and $21/MWh was for energy. For solar last year in California (where such data is readily available), electricity value of $32/MWh was comprised of $4/MWh for capacity and $28/MWh for

[7] US Energy Information Administration. (2019). "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019."
[8] Wind and solar plants are assumed to be constructed over two years, so 2021 LCOE figures reflect current costs.

energy.[9] With such minor values from capacity payments, fixing capacity rates would have little effect on the stability of revenues that is needed to obtain project financing.

For dispatchable generators, such as natural gas plants, capacity value may provide substantially more project revenue. Moreover, over 75 percent of the LCOE of natural gas combined cycle plants (NGCC) are variable costs—fuel costs as well as variable operating and maintenance costs,[10] so less fixed revenue is needed to cover the smaller proportion of fixed costs. In contrast, all of the costs for wind and solar projects are fixed—capital costs and fixed operating and maintenance costs. Financing wind and solar projects thus requires far greater stability in revenues than would be needed for NGCC financing.

The next question is whether fixed contractual energy rates are needed for QFs, or if there are market alternatives that would provide sufficient certainty in energy pricing. The NOPR asserts that such alternatives exist—from market forecasts and products to hedge energy rates, which would support financing for QFs. We believe this is unlikely for two reasons. First, market forecasts alone hardly ever suffice for wind and solar project financing, a large majority of which comes from risk-averse lenders and tax equity investors. Indeed, the Falvez Astra wind project installed in Texas in 2017 is believed to be the first unhedged merchant wind project to have received tax equity financing,[11] and no similar deals have reported since.

Second, while hedge products do support wind and solar project financing, they would not be suited for most QF projects. To hedge energy prices, wind projects have used three products: bank hedges, synthetic power purchase agreements (synthetic PPAs), and proxy revenue swaps, which we assess in a working paper published earlier this year.[12] From US project data for 2017 and 2018, the smallest wind project securing such a hedge was 78 MW, and most projects were well over 100 MW. Additionally, as hedges rely on wholesale market access and liquid electricity trading, all of the projects were in ISO regions. Solar power has lagged wind in the utilization of financial hedges, and only one product, a synthetic PPA, has been used for US solar projects installed to date.[13] The lesser viability of solar hedging contracts is due, in part, to the fixed transaction costs of financial hedges and the generally smaller size of solar projects. For even large QFs in an ISO region, it is doubtful that

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[9] Wiser, R. (2019). "The Impacts of Variable Renewable Energy on Wholesale Power Prices: Implications for the Merchant Value of Wind and Solar." Lawrence Berkeley National Laboratory (LBNL). Berkeley, CA.
[10] US Energy Information Administration. (2019). "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019."
[11] Metcalf, R. (2016). "Sponsor Seals Tax Equity for Merchant Wind Project in Texas." *Power Finance & Risk*.
[12] Bartlett, J. (2019). "Reducing Risk in Merchant Wind and Solar Projects through Financial Hedges." *Resources for the Future Working Paper*.
[13] Two solar projects under construction, Misae and Holstein, have secured bank hedges. However, both projects are 200MW or larger, illustrating the difficulty in obtaining a bank hedge for smaller (sub-100MW) projects.

a bank hedge or proxy revenue swap would be a viable option due to their fixed costs, leaving a synthetic PPA as the sole hedging option. For smaller QFs (e.g., less than 5 MW) or QFs outside ISO regions, no hedging options that could support project financing would be available.

Fixed Rates for QFs Are Essential to Developing Renewables in Certain Markets

In the discussion of whether fixed rates are needed for QF financing, the NOPR references EIA data that "since 2005, QFs have made up only 10 to 20 percent of all renewable resource capacity in service in the United States, demonstrating that most renewable resources no longer need to rely on PURPA avoided cost rates to sell their output economically." While this is true—PURPA accounts for a minority of total renewable capacity developed in the US—fixed rates for QFs are needed for certain generators to obtain financing.

In the previous section, we discussed how large wind or solar projects in ISO regions may have hedging options that would support their financing. Additionally, in 29 states and the District of Columbia, renewable portfolio standard (RPS) policies mandate the growth of renewable capacity. However, for small renewable generators anywhere in the US, as well as renewable generators of potentially larger size but in non-ISO markets or those without an RPS mandate, PURPA may be necessary. From the EIA data for capacity additions between 2008 and 2017, four of the six largest states for QF capacity additions are not in an ISO: North Carolina, Idaho, Utah, and Georgia.[14] Furthermore, in three of those states (North Carolina, Idaho, and Utah), QF capacity accounted for a large majority of total wind and solar capacity added. The data thus indicate that in certain markets, PURPA has been essential to the overall development of renewable power. In other markets, PURPA may only be needed for small generators, but those are specifically the generators for which the law was designed.

Forward Curves Could Enable QF Financing Without Exceeding Incremental Costs

The commission has proposed that market forecasts of energy rates—known as forward price curves—could be used to determine fixed energy rates over the term of the QF's contract. The NOPR states that "frequently, price forecasts are available for LMPs in RTOs/ISOs, for liquid market hubs located outside of RTOs/ISOs, and for natural gas pricing hubs." Although we favor the use of market-based price forecasts, such forecasted prices may need to be adjusted so that they fully reflect a utility's avoided costs. Specifically, a market hub price outside of an RTO/ISO would likely need to be increased by a transmission cost if the utility is not adjacent to that hub. The same would

[14] US Energy Information Administration. (2018). "Today in Energy: PURPA-Qualifying Capacity Increases, But It's Still A Small Portion of Added Renewables."

be true for natural gas prices if there are pipeline constraints between the gas hub and the utility's combined cycle plant used to set the QF's rates. Lastly, while natural gas prices and heat rates would establish the fuel cost (in $/MWh terms) for the combined cycle plant, the plant's variable operating and maintenance costs (estimated by investment bank Lazard to be approximately $4/MWh) would need to be added to compute the utility's avoided costs.[15]

If the appropriate adjustments are made to reflect any missing components of a utility's avoided costs, market price forecasts that account for the location and generation profile of the QF could address the three cost concerns discussed earlier: (i) the expected trends in average wholesale power prices, (ii) the locational and time-of-delivery differences between QF prices and average prices, and (iii) the effects of anticipated increases in renewable generation on the energy value of QFs. Accounting for locational differences would appropriately incorporate transmission constraints in the rate calculations, thereby rewarding QFs installed in more valuable areas. Including time-of-delivery effects would recognize the variation in daily and seasonal power pricing, compensating QFs according to the value of their generation profiles. Market electricity price forecasts would take into account future natural gas prices, changes in renewable and non-renewable generation capacity, trends in power demand, and other factors. While future prices would inevitably differ from such forecasted prices, market forecasts should neither consistently underestimate nor overestimate future prices. At the same time, fixed energy rates based on market forecasts would allow QFs to obtain financing, whereas variable energy rates generally would not.

Use of Competitive Solicitations

Although forward curves would tend to appropriately determine fixed avoided cost rates, there is one plausible scenario in which they would be deficient. If the fixed rates, based on forward curves, were set and developers attempted a large amount of QF capacity at those rates, then the rates could be excessive. For example, if 3 GW of solar QF capacity were put into the interconnection queue, the rates might be reasonable for the first GW, but the effect of increased midday generation would be that the second and third GW of solar would have progressively less value. Indeed, over 3 GW was put into the Michigan PURPA pipeline before a compromise was reached to install about 600 MW.[16] In this type of scenario, fixed rates (set by forward curves) could have a capacity limit after which the rates would no longer be valid. If proposed QF development exceeded the capacity limit, a competitive solicitation could be used to determine which QF projects would receive the PURPA rates. The process could continue the following year with forward curves setting new fixed rates for a certain amount of capacity, and competitive solicitations used again if the capacity were

[15] Lazard. (2018). "Lazard's Levelized Cost of Energy Analysis – Version 12.0."
[16] Merchant, E. F. (2019). "Michigan PURPA Settlement Set to More Than Triple State's Solar Capacity." Greentech Media.

oversubscribed. It is important to stress that competitive solicitations *alone* would minimize QF costs but would not establish avoided cost rates, which depend on much more than the cost of QF generation. However, used in concert with forward curves, competitive solicitations could provide an effective complementary method.

Conclusion

The objective of PURPA to encourage QF generation without exceeding a utility's incremental cost necessitates a thorough consideration of both QF development requirements as well as the avoided costs of utilities. With respect to the former, wind and solar plants have low capacity values and entirely fixed costs, so stable energy pricing is essential for financing. For small wind and solar QFs and those outside of competitive wholesale markets, the required stability in energy prices needs to come from PURPA contracts. With respect to the latter, a utility's avoided costs should incorporate average power price changes, from such factors as natural gas prices, electricity demand, and generation capacity. However, given the particular locations and intermittent nature of most QF generation, avoided costs should also be place and time specific, and these values may change over time—especially with increasing solar and wind generation. We believe the use of forward curves to set fixed rates for QFs, with any needed adjustments for forecasted prices to fully reflect a utility's avoided costs, is the preferred method to satisfy PURPA's objective. Competitive solicitations may also have a limited role as a complement to forward curves.

While PURPA may not be responsible for a majority of renewable capacity installations, it remains a vital policy for renewables. In states without competitive wholesale markets or RPS mandates, it may be the primary mechanism for developing renewable power. In other states, it may still be needed for small generators given the barriers to accessing power markets and financial products. With the continued importance of PURPA, setting rates in the way that is most consistent with the law's objective is crucial.

Sincerely,

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