BEFORE THE PUBLIC SERVICE COMMISSION

OF THE COMMONWEALTH OF KENTUCKY

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)))))))))	CASE NO. 2020-00349

Direct Testimony of Justin R. Barnes

On Behalf of Kentucky Solar Industries Association, Inc.

March 5, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My names is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Kentucky Solar Industries Association, Inc. ("KYSEIA").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I submitted testimony to the Commission in Case No. 2020-00174 addressing the Kentucky Power Company's most recent general rate case application on aspects of the application addressing the proposed N.M.S. II tariff and rates for small power production facilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the *Database of State*

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

Incentives for Renewables and Efficiency ("DSIRE") project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS RELATES TO THIS PROCEEDING.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in rate design and utility regulation. For example, as part of my current duties overseeing EQ Research's general rate case tracking service, I have reviewed dozens of general rate case applications, including the methods used by different utilities to develop cost of service studies and different rate designs, as well as the decisions made by regulators in those proceedings.

I have submitted testimony before utility regulatory commissions in Colorado, Hawaii, Georgia, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, South Carolina, Texas, and Utah, as well as to the City Council of New Orleans, on various issues related to distributed energy resource

("DER") policy, net metering, rate design, and cost of service.[2] These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My *curriculum vitae* is attached as Exhibit JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. My testimony addresses a single aspect of the Kentucky Utilities Company ("KU" or "the Company") general rate case application, the Company's tariffs for establishing purchase rates for energy and capacity from Qualifying Facilities ("QFs") under Rider SQF for facilities of 100 kW or less and Rider LQF for facilities from 100 kW to 20 MW. I address both the changes that the Company requests to those tariffs in its application as well as the existing structure of those tariffs as it pertains to the proper identification of avoided costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S QF RIDERS.

A. My recommendations to the Commission are as follows:

- The Company's avoided energy costs under Rider SQF and Rider LQF should be modified to include hedging value and avoided line losses.
- The contract term for Rider SQF should be extended to a minimum of five years.
- Capacity compensation should be established for Rider SQF under the same methodology I recommend for Rider LQF.

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

- The Company's proposed revisions to the methodology for establishing energy rates Rider LQF should be rejected.
- The Commission should direct the Company to modify Schedule LQF to provide that the current capacity calculation methodology only applies during periods of resource sufficiency as indicated by the Company's most recent integrated resource plan ("IRP") or related proceedings in which the Company proposes to build or otherwise acquire capacity.
- The Company's avoided capacity cost during periods of resource insufficiency should be established based on the costs of a proxy unit defined by the Company's most recent IRP as the next unit addition.
- The Commission should consider establishing a longer term than five years for QF contracts that involve the sale of capacity because capacity planning and acquisition is fundamentally a long-term exercise and the associated avoided capacity costs are long-term in character.

Q. DO YOU HAVE ANY OVERARCHING COMMENTS TO THE COMMISSION WITH RESPECT TO YOUR RECOMMENDATIONS?

A. Yes. I discuss certain aspects of the Commission's order revising the avoided cost methodology employed by the Kentucky Power Company ("KPC") in Case No. 2020-00174. I respect the precedent set by the Commission's decision in that case with respect to pricing and contract terms, but I urge the Commission to appreciate that KU exists within a different energy landscape than KPC because it is not part of a wholesale energy and capacity market. For that reason some of the logic that the Commission applied to KPC's rates, in particular the emphasis on value as defined by a market rate, cannot be applied in an identical fashion to the Company's avoided cost rates. My testimony attempts to apply the broader intent that I see present in the Commission's determinations regarding KPC to the different circumstances present in KU's service territory, and should not be viewed as an effort to re-litigate those determinations.

In addition, I have attached to my testimony as Exhibit JRB-2 a report profiling the various methodologies used throughout the country used to determine avoided costs. While that report dates from 2011, the general character of the different methodologies that are employed for this purpose, and their merits and drawbacks, have not changed appreciably during that time. As such, it remains a valuable resource for the Commission when considering options available for avoided cost ratemaking for the purposes of the Company's tariffs. It provides far more detail on different methodologies than I can provide in my testimony.

II. RIDERS SQF AND LQF

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S RIDER SQF AND RIDER LQF AND ANY CHANGES THE COMPANY PROPOSES TO THOSE RIDERS IN THE CURRENT PROCEEDING.

A. KU offers two tariffs for purchases from QFs. Rider SQF applies to facilities of 100 kW or less and Rider LQF applies to QFs larger than 100 kW. Rider SQF provides standard rates for purchases of energy with a customer option to elect a time-differentiated rate ranging from $0.02145/kWh (off-peak) to $0.02282/kWh (on-peak) or a flat rate of $0.02173/kWh at the Company's proposed rates. Rider SQF does not contain a capacity purchase component.[3] The rates proposed for energy purchases would remain the same as those reflected in the Company's current tariff. The only change the Company requests to Rider SQF is a clarification that for the purpose of the time-differentiated rate option, holidays that fall on a weekday will be considered weekdays.[4]

Rider LQF specifies formulas under which energy and capacity purchase rates are established rather than specific rates themselves. The energy component is based primarily on hourly avoided fuel costs associated with the Company's self-owned coal and natural gas generation facilities. The Company proposes an adjustment to the language defining the hourly avoided energy cost to exclude certain fuel-related costs that the Company identifies a "fixed" in nature. The specific proposal is to add a qualifier to the reference to "actual avoided fuel expenses" such that it reads "actual fuel expenses, excluding those that are fixed and non-variable."[5]

The Rider LQF capacity component is based on an implied cost of capacity derived based on the hourly purchase price of power ($/MWh) available on the inter-utility market minus the Company's variable fuel expense. This rate is referred to as the Avoided Capacity Cost ("ACC"), which is multiplied by the capacity delivered during an hour by the QF ("CAP"). In practice the Company calculates CAP to be zero if system demand is less than the Company's available capacity (installed or previously arranged) during an hour. If system demand is

[3] Application, Minimum Filing Requirements Tab 4 [PDF 108 of 1864].
[4] Direct Testimony of Robert M. Conroy ("Conroy Direct") at p. 45 lines 13-16 [PDF 427 of 447].
[5] Conroy Direct at p. 45 lines 19-23 [PDF 427 of 447].

higher than KU's available capacity but less than the sum of KU capacity plus the capacity from the QF, CAP is limited to capacity purchased on the inter-utility market. CAP actually represents the amount delivered by the QF only if system demand is greater than both KU capacity and the capacity added by the QF.

Q. WHAT CONTRACT TERMS DO RIDER SQF AND RIDER LQF OFFER?

A. Rider SQF does not identify a contract term. Energy is only purchased on an as-available basis. Rider LQF specifies a term of one year for purchases of energy on a self-renewing basis and five years for contracts which cover the purchase of both energy and capacity.

A. Rider SQF

Q. WHAT PROBLEMS HAVE YOU IDENTIFIED IN THE COMPANY'S RIDER SQF?

A. There are three primary problems. First, Rider SQF fails to provide a payment for capacity. Second, and relatedly, it fails to offer a contract of any duration to small QFs. This is inconsistent with the Commission's recent decision requiring KPC to revise its equivalent tariffs (COGEN/SPP). In Case No. 2020-00174 the Commission directed KPC to revise these tariffs to establish a minimum contract term of five years.[6] While the Commission did not elect to require fixed energy rate pricing for the five-year term it did effectively establish such a requirement for capacity purchases. That requirement was applied to both the rate for small QFs (100 kW or less) and large QFs. An equivalent treatment should be applied to the

[6] Commission Case No. 2020-00174. Order dated January 13, 2021, p. 100 [PDF 100 of 134] and p. 113 [PDF 113 of 134].

Company's Rider SQF. There is no economic rationale for differentiating compensation for the provision of capacity due a QF solely on the basis of the size of the facility.

Finally, the Company's calculation of avoided energy costs is essentially confined to fuel and variable operations and maintenance ("O&M") costs, which the Company refers to as its hourly marginal energy costs.[7] This narrow focus excludes the value that accrues from additional price stability over the course of a QF contract. Or from a different perspective, QF electricity reduces the volume of fuel that is used to generate electricity and therefore reduces the volumes hedged natural gas and coal fuels.

It also excludes a gross-up for avoided line losses that accrue when dispersed QF generation serves nearby loads and displaces large-scale central scale generation that must be transported longer distances and pass through more transformer infrastructure in order to reach customer loads at their respective service voltages. Accordingly, localized generation has an incrementally higher energy and capacity value than centralized generation (*i.e.*, if transmission line losses are 5%, 1 MWh of QF energy displaces 1.05 MWh of centralized generation). The energy and capacity rates should therefore both be grossed up for line losses.

[7] Company response to PSC 3-19(a) [PDF 33 of 90].

Q. DO OTHER STATES INCORPORATE A HEDGING BENEFIT INTO THEIR AVOIDED ENERGY COST PRICING MODEL?

A. Yes. The North Carolina Utilities Commission ("NCUC") has unambiguously stated that avoided energy costs should include a fuel price hedging value. Most recently, in its decision on 2018 avoided cost rates, it reiterated a prior finding that including a fuel price hedge value is appropriate. Specifically, the NCUC stated:

> In the Sub 140 Phase One Order [referring to the 2016 avoided cost rate update proceeding] the Commission found that renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a QF reduces the amount of fuel the utility otherwise would need to purchase. In doing so, the Commission acknowledged that purchasing solar power can be seen as the equivalent of buying natural gas forwards. Based upon the foregoing and the entire record herein, the Commission finds that the evidence in this proceeding demonstrates again that there are fuel price hedging benefits associated with renewable generation. Purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that must be purchased and, therefore, the costs that the utilities would incur toward fuel procurement.[8]

Q. DO OTHER STATES AND UTILITIES RECOGNIZE LINE LOSSES AS AN AVOIDED ENERGY AND CAPACITY COST?

A. Yes. In fact, the existence of avoided line losses as an avoided cost is typically not controversial because their existence is an objective fact that is reflected in retail rates that are differentiated by service voltage to reflect losses, or the lack thereof (*i.e.,* where customers receive service at higher voltages).[9] Such differentiation is

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[8] NCUC Docket No. E-100, Sub 158. Order Establishing Standard Rates and Contract Terms for Qualifying Facilities. April 15, 2020. p. 61.

[9] In my experience, the primary disagreements on appropriate treatment of line losses centers on the amounts and variations in marginal losses that occur during high load vs. lower load period, because high loads produce greater marginal losses (i.e., on-peak losses are higher than average losses).

found in many utilities' purchased power tariffs. For instance, Duke Energy Florida's as-available energy purchase rates specify that deliveries of energy from QFs are subject to a delivery voltage adjustment factor defined as the reciprocal of the applicable delivery efficiency factor.[10] Likewise, in North Carolina, Duke Energy Carolina's purchased power tariff applies a premium for purchases associated with QFs interconnected at distribution voltage relative to interconnected at transmission voltage.[11] Finally, the avoided energy pricing methodology the Commission recently adopted for KPC in Kentucky, providing that the avoided energy price be set at the variable PJM locational marginal price ("LMP") implicitly include a marginal transmission loss component, as well as a congestion component.[12]

Q. DO KENTUCKY'S REGULATIONS GOVERNING PURPA ADDRESS LINE LOSSES.

A. Yes. Section 5 of 807 KAR 5:504 provides that in determining the final purchase rate for QFs several factors must be taken into account. Section 5(c) expressly includes among those factors "Savings or costs resulting from line losses that would not have existed in the absence of purchases from a qualifying facility."

[10] Duke Energy Florida. Tariff Section IX, Cogeneration. Appendix A, *available at*: https://www.duke-energy.com/Home/Billing/Rates#tab-d589a156-227c-46b6-8a5b-21aa87e19ff0

[11] Duke Energy Carolinas. Schedule PP, *available at*: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/ncschedulepp.pdf?la=en

[12] *See for example*, PJM presentation on Locational Marginal Pricing Components. July 13, 2017, *available at*: https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/mkt-optimization-wkshp/locational-marginal-pricing-components.ashx

Q. DO YOU HAVE ANY OBJECTION TO THE COMPANY'S PROPOSED CLARIFICATION OF HOW HOLIDAYS ARE ASSESSED UNDER THE TIME-VARYING RATE OPTION OF RIDER SQF?

A. No.

B. Rider LQF

Q. WHAT PROBLEMS HAVE YOU IDENTIFIED IN RIDER LQF TARIFF?

A. There are several problems, which include: (a) the opacity of the actual rates that will apply to purchases, (b) the derivation of the energy rates, including the changes proposed by the Company, and (c) uncertainty created by the manner in which the Company calculates capacity compensation.

Q. PLEASE ELABORATE ON YOUR CONCERNS REGARDING THE OPACITY PRESENT IN LQF RATES AND THE ASSOCIATED COMPENSATION DUE TO QFS.

A. This issue is present in both the energy and capacity compensation rates, and the lack of transparency creates an unreasonable amount of uncertainty for a prospective QF generator because the generator has no way of knowing the level of compensation that may be provided for the provision of energy services. For instance, although the energy rate methodology appears to be based on a methodology similar to what is used to determine the energy rates for Rider SQF, the actual amounts are not stated. Rather, the rate is variable based on actual fuel expenses on a monthly basis, and a prospective QF has no visibility into how that might vary over the course of a contract.

Q. HOW IS THIS UNCERTAINTY DIFFERENT THAN THE UNCERTAINTY THAT A QF FACES WITH RESPECT TO THE USE OF THE VARIABLE PJM LOCATIONAL MARGINAL PRICE ("LMP") IN KENTUCKY POWER TERRITORY?

A. While I continue to believe that ratepayer indifference between utility-owned and independently-owned generation is best served by aligning energy prices with projections used by utilities to justify their own investments, at least PJM LMPs are publicly available. This allows a prospective QF generator to evaluate likely pricing based on their own analysis of historic data and future expectations. No such capability exists under the Company's energy pricing methodology, and the Company designates information that could allow such insights to be generated as confidential.[13]

Q. PLEASE ELABORATE ON YOUR OBJECTIONS TO THE ENERGY RATE CALCULATION ITSELF IN RIDER LQF.

A. I have several objections to the calculation. First, the use of the term "actual fuel expenses" is inappropriate because as written it excludes variable operations and maintenance ("O&M") costs which are properly considered avoided energy costs because they are incurred on a $/MWh basis. Variable O&M expenses are included in the Company's calculation of avoided energy costs under Rider SQF as they should be.[14] However, they would presumably not be included in the energy rate

[13] Company response to KY OAG and KIUC 1-172 Attachment 2 "CONFIDENTIAL Att 2 Avoided _11075_1." [PDF 182 of 433].
[14] *Id*. See tabs 2 and 7 [PDF 180 and 181 of 433].

under Rider SQF under either the current or proposed tariff language. This difference in the energy rate calculation needs to be rectified.

Second, as I previously noted, the Company proposes to further exclude from actual fuel expenses those that it determines to be "fixed and non-variable". The Company provided examples of such "fixed" costs as including natural gas transportation fees, fixed rail transportation costs, rail car leasing, and barge fleeting though it also stated that "this list is not meant to be all inclusive if the Company incurs additional fuel-related costs that meet the revised definition in the tariff.[15]

There are multiple problems with the Company's proposal. First, the open-ended and seemingly entirely utility-discretionary nature of the designation of certain costs as fixed opens the door to the prospect for arbitrary decision-making at a future date that has the effect of reducing compensation due to a QF that is already under contract with the Company. Adding such one-sided discretionary authority would render the a QF contract meaningless, as it could allow for the Company to effectively contract away compensation due to a QF by executing longer-term agreements that it then characterizes as "fixed" costs.

In addition, as I discussed in the context of the Company's Rider SQF rates, those rates exclude a hedging benefit and a line loss adder. The Company's existing and proposed language governing energy rate compensation due to QFs exclude those avoided costs as well, and therefore understate the true costs that the Company avoids when contracting with a large QF.

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[15] Company response to PSC 3-19(a) [PDF 33 of 90].

Q. HOW SHOULD THE ENERGY RATES UNDER RIDER LQF BE ESTABLISHED?

A. First, the Commission should reject the Company's proposed changes to the tariff language governing energy rate compensation under Rider LQF. Second, the calculation of the energy rate should be set in accordance with my recommendations for the Rider SQF energy rate, such that it includes variable O&M expenses and hedging value in addition to fuel costs. This can be effectuated by repeating the same rates in Rider LQF or referring to Rider SQF for the purpose of stating the applicable energy rates.

Q. PLEASE EXPLAIN YOUR OBJECTIONS TO THE COMPANY'S METHODOLOGY FOR PRICING CAPACITY COMPENSATION UNDER RIDER LQF.

A. There are three primary problems: (a) as with the energy pricing methodology, the pricing methodology and ultimate rates are entirely opaque, (b) it fails to compensate a QF for the capacity they deliver by instituting conditions that eliminate the payment at certain times; and (c) it fails to reflect that capacity and capacity planning are fundamentally long-term in nature. These three problems are interrelated as they arise from the basic structure of the capacity pricing regime.

Q. PLEASE EXPLAIN HOW THE THREE INSUFFICIENCIES IN THE RIDER LQF PRICING METHODOLOGY ARE INTERRELATED.

A. The capacity rate calculation has as its foundation in the price that the Company pays for purchased power "from the inter-utility market". The fundamentally erroneous assumption that underlies this calculation is that non-utility resources will always be available and sufficient should the Company have a need to call on them. In other words, there will always be a counterparty willing to sell to the Company if it experiences a shortfall in resource availability relative to load.

This conceptual framework defies the basic logic behind capacity pricing itself. Capacity has value precisely because it represents a resource that can be called upon when needed, or in the case of solar, wind, or other intermittent technologies, can be expected to be available at certain times due to its production characteristics. A capacity payment functions to allow a generator to recover its fixed costs that are not recoverable through the sale of energy, such that it functions as a payment for availability. If those fixed costs cannot be recovered by the combination of energy and capacity compensation, or a generator does not believe they will be, the generation unit will not be built in the first place.

The Company's capacity pricing methodology has a circular and asymmetric logic to it. Effectively, the Company will accept capacity when it needs it, but will not commit to purchasing capacity in any specific volume at any specific rate. Yet the entire logic behind capacity pricing and value is that the capacity payment is provided precisely to ensure that capacity is available when it is needed via a commitment to the purchase.

Q. HOW DOES THIS FAIL TO REFLECT THE LONG-TERM NATURE OF CAPACITY PLANNING?

A. The use of an as available market price represents only an immediate short-term time horizon. Capacity planning takes a long-term outlook because ensuring that sufficient capacity exists to meet demand cannot be wholly reliant on short-term market purchases. Doing so exposes ratepayers to volatility, and taken to the furthest degree, creates no assurance that demand can be met. Assuming availability from non-contracted resources is particularly fraught if one considers that periods of particularly high demand are often regional in nature insofar as they are driven by regional weather phenomenon.

Q. PLEASE ELABORATE ON YOUR OBJECTION TO THE OPACITY OF THE CAPACITY RATE CALCULATION.

A. In order for a QF to assess the potential value of providing capacity to the Company, it would have to know the nature and amounts of historic transactions of this type, or projections of the future need for power purchases. Neither would seemingly be available to a prospective QF. The inherent uncertainty would likely cause a prospective QF to assume a zero value for this component, and therefore discourage construction of QFs.

Q. IS SUCH A SITUATION CONSISTENT WITH THE COMMISSION'S RECENT DECISION ON KPC'S AVOIDED COST RATES?

A. No. In the case of KPC the Commission found that "the avoided capacity rate should be the zonal net CONE ["Cost of New Entry"] for the delivery years that have an established CONE at the time of the contract and the last known net CONE for the remainder of the term. This will balance the interests of Kentucky Power and the QF by enabling QFs to estimate the avoided capacity rates from publicly available documents and providing a market based capacity value specific to Kentucky Power's location."[16] Thus the Commission found that the existence of

[16] Commission Case No. 2020-00174. Order dated January 13, 2021, p. 100 [PDF 100 of 134].

publicly available data was an important factor for balancing the interests of KPC and QFs that may consider locating within its territory. The need for that same balance should be applied to KU's avoided cost rates.

Q. HOW DO KENTUCKY'S REGULATIONS GOVERNING PURPA ADDRESS CAPACITY PRICING?

A. Section 4(b) of 807 KAR 5:504 specifies that "Rates for energy or capacity or both offered on a legally enforceable basis shall be based at the option of the qualifying facility on either avoided costs at the time of delivery or avoided costs at the time the legally enforceable obligation is incurred." Section 5 of 807 KAR 5:504 further dictates that purchase rates consider a series of factors associated with the availability or energy or capacity from a facility (subsection a) and the "Ability of the electric utility to avoid costs due to deferral, cancellation, or downsizing of capacity additions, and reduction of fossil fuel use." Collectively, these sections provide that a QF is entitled to capacity compensation not on the basis of as-needed non-firm market purchases, but on the ability of the QF to substitute for utility investments.

Q. WHAT IF THE UTILITY DOES NOT HAVE ANY PLANNED INVESTMENTS ON A NEAR-TERM OR LONG-TERM TIME HORIZON?

A. In theory, the capacity value could be zero if that is the case. However, it cannot be assumed that it will always be the case since utility plans are frequently updated with new retirements or revisions to load forecasts that can transform a capacity surplus into a deficiency. The Company's LQF tariff fails to account for this possibility as it would continue to use a short-term market purchase-based formula no matter what capacity need is identified and regardless of how the Company plans to meet it.

Q. DOES KU HAVE AN IMPENDING NEED FOR CAPACITY?

A. The Company's 2018 joint IRP suggests a potential need for 50 – 550 MW of new or replacement capacity starting in 2026 using a scenario where its operating units have a 55-year lifetime and the base case load scenario. This need rises to 2,000 – 2,500 MW by 2033 as further retirements take place. The associated long-term resource plans include differing amounts of natural gas combined cycle ("NGCC") capacity and 300 – 500 MW of solar capacity depending on the load scenario and whether or not a price on carbon is assumed.[17] Furthermore, on January 7, 2021 KU and Louisville Gas and Electric jointly issued a request for proposals ("RFP") seeking 300 – 900 MW of replacement capacity sized at 100 MW or larger beginning in 2025 to 2028, including at least 100 MW of battery storage.[18] Accordingly, the Company has demonstrated a need for capacity in the upcoming years, and its next IRP due October 19, 2021 should present further clarity on potential additional capacity needs in the mid- and long-term.

Q. COULD RESOURCES SECURED VIA RIDER LQF PROVIDE CAPACITY TO MEET SUCH FUTURE NEEDS?

A. There is no reason why they could not do so. The Company's modeling in the 2018 IRP assumed that solar would contribute to summer peak loads at 80% of its total

[17] Commission Case No. 2018-00348. LGE-KU 2018 IRP Volume 1, at pp. 5-37 to 5-39. October 19, 2018 [PDF 42-44 of 117].

[18] KU. Press release. "LG&E and KU request bids for energy to continue to reliably serve customers." January 7, 2021. *Available at*: https://lge-ku.com/newsroom/press-releases/2021/01/07/lge-and-ku-request-bids-energy-continue-reliably-serve-customers

capacity, and stated that the existing E.W. Brown solar facility contributed at a ratio of 57% of its nameplate rating to the July 2017 annual peak.[19] Smaller QF generation (in relation to typical fossil unit sizes) also have the advantage of being able to be deployed relatively quickly and in increments that reduce the existence of excess or underutilized capacity created by relatively "lumpy" fossil additions or due to forecasting error (*e.g.,* in load forecasts).

Q. HOW SHOULD THE COMMISSION REMEDY THE LACK OF ALIGNMENT BETWEEN THE COMPANY'S CAPACITY PLANNING AND HOW IT COMPENSATES QFS FOR PROVIDING CAPACITY UNDER RIDER LQF?

A. In the most general sense, because KU self-supplies its resource needs, its rates for the purchase of power from non-utility generators should be tethered to its IRP process and any other proceedings in which it seeks approval to build or otherwise acquire capacity. Doing so ensures that non-utility generation is placed on a level playing field with utility-owned generation, and that ratepayers are rendered indifferent to whether their energy needs are met with utility-owned or non-utility-owned generation. Ideally, this would extend to energy pricing as well, since energy cost projections are necessary to assess the merits of one resource relative to another, and to the extent that a utility like KU wishes to acquire new assets, those projections should function as a benchmark for establishing the "value" of a given non-utility-owned project.

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[19] *Ibid*. Volume 3, E.W. Brown Solar Profile, 2017, at p. 3 and 2018 IRP Resource Screening Analysis, p. 9 [PDF 11 of 93 and 30 of 93].

From the standpoint of capacity compensation, the Company's LQF tariff should be modified to provide that the current short-term market purchase-based regime is only applicable during periods when the Company is resource sufficient according to its IRP or other indicators of an intention to acquire capacity, such as an application for approval to build or acquire a specific resource.

Otherwise, capacity should be valued according to the avoided cost of deferred, reduced, or cancelled investments or purchases, as contemplated by 807 KAR 5:504. Given KU's position as a self-supplying utility, I suggest the so-called "proxy unit" method of determining capacity costs and capacity compensation, where the proxy unit is designated by the preferred next resource addition in the Company's IRP. The capacity contribution applied to non-dispatchable resources, such as solar or wind, should be based on the assumptions used in the IRP.

Q. ARE THERE ANY NUANCES THAT THE COMMISSION SHOULD APPRECIATE WHEN CONSIDERING A MORE APPROPRIATE AVOIDED COST RATE METHODOLOGY FOR KU?

A. Yes. In revising the methodology used to determine KPC's avoided cost rates, the Commission, in its words, chose to "avail itself of the new capability to require variable energy rates and finds that the avoided energy rate should be the variable LMP at time of delivery."[20] KU exists in a different set of circumstances from KPC in that it is not part of an organized wholesale market for energy and capacity, and as such its avoided costs have a different character than KPC's. My recommendation for the use of a proxy unit methodology based on a proxy unit

[20] Commission Case No. 2020-00174. Order dated January 13, 2021, p. 100 [PDF 100 of 134].

identified in the Company's IRP attempts to improve upon the capacity valuation methodology. However, the proxy unit methodology has historically been employed as a dual energy and capacity cost determination method based on the future energy and capacity costs associated with the proxy unit.

Stated another way, the proxy unit has both energy and capacity costs, ergo, the avoided costs associated with the proxy unit are the costs associated with building and operating that unit over its lifetime. In this case, the marginal energy costs are not those associated with the current system, they are the costs associated with operating the proxy unit over the course of its useful life. Likewise, the capacity costs are also those associated with the proxy unit, which would not change if the proxy unit were built. Collectively, these nuances indicate that true establishment of avoided costs should reflect the *long-term nature* of utility generation investments in the form of long-term contracts with QFs that avoid to defer those investments. This is particularly true for capacity costs that, once expended, are fixed in character.

All of this is to say that long-term contracts for QFs that contract to provide capacity are appropriate given that the counterfactual scenario where a utility does make an investment in a generation unit (*i.e.,* absent the capacity provided by a QF) produces a fixed cost recoverable over the lifetime of that generation unit. The minimum five-year contract adopted for KPC, and the current five-year contract used in KU's Rider LQF fail to reflect the reality that a QF avoids the fixed costs that were being contemplated at the time the QF established a legally enforceable obligation and avoided the incurrence of those costs.

Q. DO YOU HAVE ANY CONCLUDING OBSERVATIONS TO MAKE REGARDING THE INTERPLAY OF UTILITY CAPACITY EXPANSION OR REPLACEMENT PLANS, INTEGRATED RESOURCE PLANNING, AND AVOIDED COST RATEMAKING?

A. Yes. My understanding of the integrated resource planning process in Kentucky is that utility IRPs are not subject to an "approval" process, or otherwise considered determinative with respect to a utility's decisions regarding resource additions or acquisitions. The effectiveness of my recommendation that avoided capacity costs be "tethered" to the integrated resource planning process is contingent on the Commission not permitting KU or any other utility to engineer circumstances that allow it to evade the purpose of this tethering, given that the obligation to offer payment for capacity is tied to a utility's relative resource sufficiency or deficiency.

By way of further explanation, such "evasion" can occur when future utility resource needs are left vague or conditional in the IRP, denoting that future capacity needs are uncertain, making resource sufficiency or deficiency difficult or impossible to ascertain. Only later, the utility makes decisions that imply or create such certainty (*e.g.,* determining a plant retirement date) and seeks to fill that need according to its own preferences (*e.g.,* issuing an RFP) without a reasonable opportunity for QFs to meet that need in part or in full. Thus a resource deficiency exists, but the utility represents that it does not because it is in the process of securing resources, or has secured resources, to meet the need. The Commission should not tolerate such actions that act to circumvent the intent of establishing avoided cost pricing and a level playing field for QFs.

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S QF RIDERS.

A. My recommendations to the Commission are as follows:

- The Company's avoided energy costs under Rider SQF and Rider LQF should be modified to include hedging value and avoided line losses.
- The contract term for Rider SQF should be extended to a minimum of five years.
- Capacity compensation should be established for Rider SQF under the same methodology I recommend for Rider LQF.
- The Company's proposed revisions to the methodology for establishing energy rates Rider LQF should be rejected.
- The Commission should direct the Company to modify Schedule LQF to provide that the current capacity calculation methodology only applies during periods of resource sufficiency as indicated by the Company's most recent integrated resource plan ("IRP") or related proceedings in which the Company proposes to build or otherwise acquire capacity.
- The Company's avoided capacity cost during periods of resource insufficiency should be established based on the costs of a proxy unit defined by the Company's most recent IRP as the next unit addition.
- The Commission should consider establishing a longer term than five years for QF contracts that involve the sale of capacity because capacity planning

and acquisition is fundamentally a long-term exercise and the associated avoided capacity costs are long-term in character.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

JUSTIN R. BARNES

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EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst*,* September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

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REVIVING PURPA'S PURPOSE: The Limits of Existing State Avoided Cost Ratemaking Methodologies In Supporting Alternative Energy Development and A Proposed Path for Reform

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REVIVING PURPA'S PURPOSE: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Proposed Path for Reform

I. OVERVIEW

Because of the inability of independent power producers to sell their efficient and clean electricity into monopoly-controlled markets, Congress in 1978 enacted the Public Utilities Regulatory Policies Act (PURPA). PURPA encouraged the development of alternative power, including renewable energy and cogeneration, by requiring utilities to purchase energy and capacity from qualifying facilities (QFs) at their incremental, or avoided costs. Regarded as a successful policy tool for renewable energy and cogeneration growth, particularly in states like California, New York and Maine, PURPA's impact faltered in the 1990s, as lower natural gas prices and increased competition in wholesale markets, including the introduction of competitive bidding as a way to set avoided cost rates in some jurisdictions, reduced avoided cost payments to renewables and cogeneration under PURPA.

During this time period, however, many states enacted renewable energy policies such as Renewable Portfolio Standards, public benefit funds and green power pricing programs. The policies, along with federal and state tax incentives, helped to revive renewable energy development in the late 1990s even as PURPA's influence abated.[1] Congress limited PURPA's scope further through an amendment in EPAct 2005 which allows utilities to apply to the Federal Energy Regulatory Commission (FERC) for relief from the mandatory QF purchase obligation upon a showing that QFs have access to competitive markets. FERC subsequently interpreted broadly that all Regional Transmission Organizations (RTOs) provide such competitive markets, thereby limiting PURPA's influence to non-RTO regions, primarily in the Southeast and Northwest. In some jurisdictions – most recently, California -- utilities have applied for and received at least partial relief from the mandatory purchase obligation under PURPA.[2] This report is focused on current and historical

[1] *Renewable Energy Policies and Markets in the United States*, Eric Martinot, Ryan Wiser, and Jan Hamrin Center for Resource Solutions, at www.martinot.info/Martinot_et_al_CRS.pdf.

[2] *See* FERC Order 681, online at *www.ferc.gov/whats-new/comm-meet/072006/E-2.pdf* (establishing regulations from relief of PURPA obligations, as well as certain rebuttable presumptions regarding competitiveness of markets

jurisdictions where relief from the mandatory purchase obligation under PURPA has *not* been granted.

Notwithstanding these developments, the need for alternative-energy power markets remains. PURPA, of course, survives, and its influence may increase in the coming decade. A recent FERC decision, *Re: California Public Utilities Commission*,[3] affords states increased flexibility to set resource-specific avoided cost rates through PURPA. Resource-specific rates are expected to offer greater financial support to alternative power than calculation of a single avoided cost rate based on consideration of all of a utility's energy sources. Other factors may further reinvigorate PURPA, including anticipated EPA rules imposing more stringent standards for emissions (which may increase the cost of some conventional power sources)[4], the need for new electric capacity as a result of the expected closure of many old and dirty coal-fired power plants, and predictions of rising energy costs. These recent developments reopen fundamental questions about how PURPA should be interpreted through state PURPA policies and avoided cost methodologies.

To address these questions, this report undertook a comprehensive review, the first in more than a decade, of the different ways by which state utility commissions calculate avoided cost rates for QFs under PURPA to identify the factors and underlying state policies that account for the broad range of approaches. The report also examined the use of the avoided cost concept for purposes of energy efficiency programs.

Based on this review, the report found that many developers are unable to fully capitalize on PURPA's benefits in light of factors such as the complex, Byzantine nature of avoided cost ratemaking at the state level which makes avoided cost ratemaking difficult for developers and regulators to fully understand. Further complicating the problem, in some states like Florida, utilities are vested with broad latitude in determining the data inputs for

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for QFs of under 20 MW or less located within established RTO/ISO footprints discussion). The majority of FERC cases granting relief from the mandatory purchase obligation, including in California, apply only to purchases from QFs of 20 MW or greater. *See, e.g.*, *Pacific Gas & Electric et. al.,* 135 FERC ¶61,234 (June 16, 2011).

[3] 133 FERC ¶ 61, 059 (2010).

[4] *See, e.g.,* http://www.reuters.com/article/2011/06/13/usa-epa-emissions-idUSN1314060920110613. As discussed infra, FERC allows states to include the avoided costs of compliance with emissions regulations in QF rates.

avoided cost calculations which creates inconsistency and puts even more downward pressure on avoided cost rates.[5] Many jurisdictions, moreover, provide only short-term (e.g., day ahead or one year) contracts for alternative power, while independent power producers typically need longer-term agreements in order to attract project financing. Collectively, these factors contribute to avoided cost rates that are inadequate to support combined heat and power (CHP) and renewable development as intended by PURPA.

In addition, the report also found that FERC's recent decision in *California Public Utilities Commission*, which allows states to set resource-specific avoided cost rates, has not yet filtered down to the state level. Only one state surveyed (Montana) offered resource-specific QF rates.[6] Moreover, even though *California Public Utilities Commission* reaffirmed that states may consider avoided environmental costs so long as they are not speculative, few states actually do so in setting avoided cost rates, even though the practice is common in energy efficiency programs.

This report concludes that PURPA can still serve as an important policy tool for development of small power producers, including renewables and CHP. However, states need additional guidance on which avoided cost methodologies are most favorable to small power producers[7] as well as an understanding of the range of options – such as resource-specific avoided cost rates and ability to account for avoided environmental costs – available to them in setting avoided cost rates. Therefore, this report recommends that FERC, as the agency responsible for developing the regulations that states must follow in calculating avoided cost rates, conduct a series of technical conferences on PURPA and,

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[5] *See* p. 22 for further discussion.

[6] No other states offering resource-specific QF rates could be located, though at the time this report was prepared, at least two other states, Idaho and Oregon were examining the possibility of resource-specific avoided cost rates.

[7] Initially, it was hoped that a model could be developed to quantify the impact of various state policy choices in avoided cost methodology on QF rates. However, because of the disparities in state methodologies and lack of availability of public data on utility cost information, development of a model was not possible. This type of model could be extremely useful in assisting states in choosing between avoided cost models, and for that reason, the report recommends that FERC consider undertaking such an analysis.

based on input from stakeholders, issue a policy statement to provide additional guidance to states on their options.

The report is organized as follows. The report begins with an overview of PURPA, as implemented by FERC regulations. Under PURPA, states have broad discretion to set avoided cost rates; however, state methodology must comply with the parameters established by FERC. The second part of the report describes different methodologies for setting avoided cost rates and the policies underlying these choices. The third part of the report will also discuss avoided cost issues related to energy efficiency programs and net metering. The Appendix contains detailed discussions of a sampling of nine states' avoided cost methodologies under PURPA, selected because they represent the range of different options.

II. PURPA and FERC

A. PURPA Overview: A utility must buy capacity and energy from "qualifying facilities," priced at the utility's avoided cost

The economic rationale for PURPA is to address market power disparity between independent power producers and utilities. Both overpayment and underpayment for power production by independent power producers can harm the customers of utilities, particularly customers of vertically-integrated monopoly utilities. It is fairly obvious that overpayment will occur if a utility pays more for power than the utility saves over the long run, and that protection of customer interests requires regulation to ensure that utilities do not overpay.

It is perhaps less obvious that customers are also at risk if a utility underpays for power from independent power producers. While the net savings represent a "bargain" for the utility's customers, setting the purchased power rate too low also discourages development of alternative resources.

If the development of alternative resources could occur at a lower cost than the utility's self-built generation, then the lost opportunity to obtain those cost savings puts customer interests in lower costs at odds with the utility's interest in building generation assets on which it is entitled to earn a rate of return. For example, excessively low rates may discourage industrial customers from investing in combined heat and power units to meet their needs for both steam and electricity. They may instead utilize less-efficient boilers for steam and purchase electricity from the utility.

The policy challenge to promote customer interests in a monopoly utility market (as well as in some partially-deregulated markets) is to find the "sweet spot" where rates are set high enough so as not to be penny-wise and pound foolish.

1. Enactment of PURPA

a. PURPA Overview: A utility must buy capacity and energy from "qualifying facilities, "priced at the utility's avoided cost

Congress enacted Section 210 of PURPA to encourage the development of cogeneration and small power production, and to overcome utilities' traditional reluctance to purchase power from non-traditional entities.[8] Under PURPA, electric utilities are required to purchase energy offered by QFs at rates that are just and reasonable to consumers and reflect no greater than the incremental cost that the utility would have otherwise incurred to generate or purchase the power supplied by the QF. Congress imposed incremental cost as a ceiling on QF rates to ensure ratepayer indifference, *i.e.*, that they would not pay any more for power because the utility purchased from a QF rather than generating the power itself or purchasing from another wholesale source.[9]

Subsequently, FERC adopted regulations to implement PURPA. FERC's regulations define "incremental costs" as full avoided costs of electric energy or capacity or both, which but for the purchase from the QF, such utility would generate itself or purchase from another source. [10] QF rates must equal but not exceed its full avoided costs. FERC's regulations establish certain guidelines that states must follow in establishing QF avoided cost rates, discussed in greater detail below, but leave the actual choice of methodology and calculation of rates to state discretion.

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[8] *FERC v. Mississippi*, 456 U.S. 742, 750 (1982).

[9] *FERC Notice of Proposed Rulemaking, Administrative Determination of Avoided Costs, Rates for Sales of Power to Qualifying Facilities, and Interconnection Facilities,* Docket No. RM88-6-00; IV F.E.R.C. Statutes and Regulations (CCH) para. 32,457 (1988).

[10] 18 C.F.R. § 292.101(6).

2. FERC Regulations

a. Factors considered in determining avoided costs

FERC's regulations list several factors that states should, to the extent practicable, take into account when calculating avoided costs, including:[11]

- The ability of the utility to dispatch the QF
- The expected or demonstrated reliability of the QF
- The duration of the utility's contract with the QF
- The ability to coordinate QF's outages with utility's outages
- The relationship between a QF's production and a utility's ability to actually avoid costs, including the deferral of capacity additions and the reduction of fossil fuel
- The costs or savings from changes in line losses as a result of QF purchases.

These factors permit either upward or downward adjustment of avoided cost rates. In some instances, the impact of these factors may disadvantage QFs: for example, as discussed in Part III.D, utilities cite QFs' limited dispatchability as a basis for withholding, or limiting QFs' eligibility for capacity payments. Likewise, downward adjustments for line losses can hurt those QFs located far from to load, which the California Commission has recognized and attempted to mitigate.[12]

b. Timing of avoided cost calculation

FERC's rules allow QFs to sell energy on an as-available basis or energy and a capacity pursuant to a contract for a set term. Rates for as-available energy sales are based on the purchasing utility's avoided cost at the time the energy is

[11] *See* 18 C.F.R. §292.304(e).

[12] *See* Part IV.D (Line Losses) *infra.*

delivered, while a QF selling pursuant to a contractual obligation may opt for avoided cost rates calculated at the time of delivery or at the time the contractual obligation is incurred.[13] When rates are calculated at the time the contractual obligation is incurred, they must be estimated for the duration of the contract. FERC holds that variation of actual avoided costs from the original estimates does not invalidate the originally determined avoided cost price.[14]

c. Standard offer rates

FERC's regulations require states to establish standard offer rates for utility purchases from QFs with a design capacity of 100 kw or less. The availability of standard rates is intended to facilitate the ability of very small QFs to sell to utilities and reduce associated transaction costs.

The 100 kw size limit is a floor for standard offers, not a ceiling. States have discretion to establish standard rates for QFs larger than 100 kw; for example, California makes a short-term and long-term standard offer contract available to QFs of 20 MW or less; Oregon standard offer contracts are for 10 MW or less; in North Carolina, some standard offers are available to small hydro and waste–to-energy QFs of 5 MW or less.

d. Competitive bidding, administratively determined rates and standard contracts

Following PURPA's enactment, most states determined avoided cost rates administratively, meaning that they held hearings to arrive at a methodology or a specific rate that represented the utility's avoided cost. States continue to determine standard offer rates for small QFs administratively.

As an alternative to administratively determined costs, some states implemented competitive bidding programs.[15] FERC also issued a notice of

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[13] 16 U.S.C. . §292.304(d).

[14] 18 C.F.R. § 292.304(b)(5) provides: "In the case in which rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery." *See also New York State Elec. & Gas Corp.*, 71 FERC 61,027 (1995) (declining to find contract in violation of PURPA where rates based on avoided costs at time contract obligation was incurred exceed avoided cost).

[15] *See, e.g.*, *Southern California Edison* Co., 70 *FERC* ¶61125

proposed rulemaking (NOPR) in 1988, which was never adopted, that identified competitive bidding as a way to set avoided cost prices for QFs. Several utility commentators observe that use of competitive bidding to set rates for larger or long-term QF contracts offers one way to correct the over-estimation,[16] though at least one state commission rejected a competitive bidding proposal that would result in rates below avoided cost – which would also violate PURPA.[17]

B. FERC Rulings

FERC has also issued several key rulings interpreting the scope of PURPA. First, FERC clarified that PURPA prohibits states from setting QF rates in excess of avoided costs.[18] Initially, in 1995, in *Southern California Edison,*[19] FERC ruled that a competitive procurement process limited to renewables only violates PURPA because by excluding all sources, the resulting rates will exceed avoided cost.

However, FERC overruled this 15-year old precedent in *California Public Utilities Commission.*[20] The case involved a challenge brought by three California utilities to a feed-in tariff program for CHP projects adopted by the California Commission to implement AB 1613, a piece of legislation intended to

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(1995)(describing California competitive bidding program developed in mid-1990s).

[16] *See PURPA: Making the Original Better Than the Sequel*, EEI Report (1995)(citing favorably introduction of competitive bid as means to correct oversupply of QF power); FERC NOPR on Competitive Bidding (proposing "mid-course correction to PURPA to address issues such as forcing utility to buy capacity it does not need or rates in excess of avoided costs").

[17] *Nevada Power Co.*, 76 Pub. Util. Rep. (PUR) 4th 626, 642-44 (Nev. Pub. Serv. Comm. 1986)(finding competitive bidding proposal requiring bids at less than avoided cost as violating PURPA).

[18] *See, e.g.*, *Connecticut Light and Power Company*, 70 FERC ¶ 61,012, at 61,023, 61,028, *reconsideration denied*, 71 FERC ¶ 61,035, at 61,151 (1995), *appeal dismissed*, 117 F.3d 1485 (D.C. Cir. 1997) (invalidating state QF rates that exceed avoided costs).

[19] *SoCal Edison*, 71 FERC ¶ 61,269 at 62,078.

[20] 133 FERC ¶ 61, 059 (2010).

promote CHP development. The utilities argued that the feed-in rates set by the California Commission violated PURPA because they exceeded the utilities' avoided cost. Among other things, the CHP feed-in tariff was technology-specific and did not take into account costs associated with other types of power available, contrary to the requirements of *Southern California Edison*.

FERC rejected the utilities' arguments. FERC reasoned that where a state has a policy of encouraging development of a particular technology, the utility is precluded from using all other sources to meet that need. Thus, the state is not required to take these other sources into account when setting avoided cost rates, and instead can set avoided cost rates specific to a given technology. [21]

Second, FERC holds that under PURPA, avoided cost rates which include environmental externalities such as pollution fees (whether actual or forecast) are properly included in the QF rate.[22] This is because PURPA requires that QF rates include those costs that are actually avoided by the utility in purchasing QF power. For that reason, avoided cost rates that include speculative or unsupported externalities that do not reflect a utility's avoided costs are not permitted. For example, if a state simply tacks on an added percentage to reflect externalities, with no additional showing of costs avoided by the utility, the rates would exceed the utility's avoided costs and would violate PURPA. As discussed in Part III.G, externalities are considered in determining avoided costs of energy efficiency programs.

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[21] Following FERC's decision, the California Commission reopened the proceeding to establish CHP QF rates in compliance with FERC's order. The California case concluded with a settlement agreement, under which the utilities established a CHP-only QF rate which reflects the cost of avoided greenhouse gas emissions and a more favorable heat rate than included in standard QF rates. In exchange for offering the rate, the parties agreed not to oppose the California utilities' petition to terminate their mandatory purchase obligation under PURPA for projects 20 MW or less. In June 2011, FERC granted the California utilities' request to terminate the mandatory purchase obligation. 135 FERC ¶ 61,234 (2011). Details on the QF-CHP Settlement Rate are described at the utilities' websites, e.g., San Diego Gas & Electric FAQ re: QF CHP rates. http://www.sce.com/EnergyProcurement/renewables/chp/chp-settlement-agreement-faqs.htm.

[22] *Petition of Biomass Gas & Electric Regarding Forsyth County Renewable Energy Plant*, Docket No. 4822-U, (Georgia Public Service Commission 2004).

Third, FERC holds that a utility's combined payment of avoided cost rates plus the value of a renewable energy certificate (REC) does not violate PURPA by exceeding avoided costs. A REC represents the environmental attributes of a renewable energy project and has a financial value independent of the value of project power. FERC explained that RECs are separate from avoided cost and do not represent payment for energy and capacity. [23]

Because avoided cost rates in today's competitive environment have declined, the added value of a REC can make a significant difference in the financial viability of a project. States can determine whether a utility or QF own RECs. As discussed in Part IV.G(3), state policy varies on ownership – both between states, as well as within a single state depending upon the type of avoided cost methodology that is adopted. For example, Montana offers QFs three different options for avoided cost, which may or may not allow the QF to retain the REC depending upon the scenario. *See* Appendix.

C. EPAct 2005 PURPA Amendment

In 2005, Congress amended PURPA to authorize FERC to relieve utilities of their mandatory obligation to purchase QF power. FERC may grant an exemption if it finds that the QF has nondiscriminatory access to competitive markets or open-access transmission services provided by a regional transmission operator (RTO).[24] Once a utility's PURPA obligation is terminated, it is no longer required to pay avoided cost rates for QF power.

In some jurisdictions, utilities have already applied for and received relief from the mandatory purchase obligation under PURPA. In situations where the mandatory purchase obligation is terminated, avoided cost pricing no longer applies.[25]

III. STATE POLICY CHOICES IN IMPLEMENTATION OF PURPA

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[23] *American Ref-Fuel*, 105 FERC ¶ 61,004 at P 23.

[24] 16 U.S.C. § 824a-3(m)(1)(A)-(C); *see also* FERC regulations implementing PURPA changes, 18 C.F.R. § 292.309(2009).

[25] FERC Order 681 (establishing regulations from relief of PURPA obligations, discussion).

A. Overview of State Policy Considerations in Avoided Cost Ratemaking

Within the parameters of PURPA and FERC's regulations, states retain flexibility over the methodology chosen to calculate avoided costs. This section examines several common variables in avoided cost rate methodology where states frequently adopt different approaches.

In some instances, the state's chosen approach represents a policy choice; for example, to encourage small power development,[26] incentivize a particular technology,[27] maintain ratepayer neutrality,[28] or spread the risks of QF contracts between QFs and ratepayers in a non-discriminatory manner. In other cases, a state methodology may reflect a desire for administrative simplicity[29] or

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[26] *See, e.g., Opinion on Future Policy and Pricing for QFs*, Decision 07-09-040 (California Public Utilities Commission 2007) ; In the Matter of Public Utility Commission of Oregon, Order No. 05-584 (May 5, 2005)(describing encouraging renewables as rationale for requiring standard offer contracts up to 10 MW.)

[27] See, e.g., *Application of Southern California Edison Company for Applying Market Index Formula and As-available Capacity Prices for Short Run Avoided Cost Payments to QFs, Decision* 10-12-0352010 Cal. PUC LEXIS 467, December 16, 2010 (describing proposed settlement QF rates to promote CHP*); In the Matter of Northwestern's Avoided Cost Tariff*, Montana Commission Order No.6973d (May 2010)(offering wind specific rate); *In the Matter of EPCOR USA North Carolina LLC v. Carolina Power & Light Company d/b/a/ Progress Energy Carolinas*, 2011 N.C. PUC LEXIS (extending standard offer contracts up to 5 MW for hog waste energy to promote technology).

[28] In theory, ratepayers should wind up no better or worse off when a utility purchases from a QF because the QF power simply substitutes for what the utility would otherwise have purchased. *See, e.g.,* California Decision 07-09-040 (declining to require utilities to enter into long-term QF contracts since ratepayers would bear brunt of excess costs), also, generally, decisions rejecting capacity payments where utility has excess capacity. Likewise, in states like Massachusetts where markets are competitive, states have difficulty justifying rates other than competitive based market rates for QF sales.

[29] See, e.g., Docket No. 09-035, 2009 Utah PUC LEXIS 420 (2009) (allowing Idaho Power to retain SAR based methodology instead of adopting Utah's resource sufficiency/deficiency methodology for administrative simplicity).

stakeholder consensus[30] or may be based on widely accepted expert practices.[31] Jurisdictions that apply market-based rates may do so because they believe that markets are sufficiently competitive for QFs to participate.[32]

Yet do the state policy differences affect outcomes for consumers? Qualitative conjectures can be made. Because of the disparity in state methodologies and the limited availability of non-confidential data used to apply those methodologies, it is difficult to create a model to quantify the impact of the policy differences.

B. **Standard Offer Rates**

As discussed in Part II, states are required to establish standard contract rates for QFs 100 kw or less. Many states make standard contracts available to QFs of up to 10 MW,[33] and California offers standard contracts to facilities up to 20 MW. Rates for standard offer contracts are usually administratively determined – either a state commission will establish a methodology for calculating avoided cost rates (the more common procedure) or a utility will

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[30] Decision 09-04-034, Decision 07-09-040. Website: http://www.cpuc.ca.gov/PUC/energy/Procurement/QF (2009) (adopting formulas with modifications proposed by various participants in proceeding).

[31] *See, e.g., In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities*, 2007 NC PUC LEXIS 1786 (approving utility use of either peaker method or DRR in light of accepted use of these methodologies in electric industry).

[32] Decision 07-09-010 (California Public Utilities Commission)(2007), Slip Op. at 7 (finding that markets are competitive and QFs above 20 MW can receive sufficient incentives through market-based rates).

[33] Utah, Montana and Oregon make standard contracts available to QFs of up to 10MW. In Idaho, standard contracts are available for facilities up to 10 MW, but in light of a recent influx of wind projects, in February 2011, Idaho temporarily reduced the standard offer limit for wind and solar to 100 kw. In Georgia, standard offer contracts are available to facilities of up to 5 MW, and in North Carolina, standard offer applies to wind, waste and solar facilities of up to 5 MW and to hydro facilities of up to 3 MW. *See* discussion, Appendix.

propose both rates and methodologies in a biennial proceeding (as in North Carolina).

States offer different options for QFs that do not meet the size-eligibility options. For example, ineligible QFs can participate in a competitive procurement or sell energy on an as-available basis if they miss the procurement cycle or negotiate a contract with the utility. *See* Appendix for details.

The next section discusses the methodologies that apply for determining avoided cost rates. Although each methodology reflects certain policy choices, another significant factor in evaluating a state's QF program are the size limits for standard offer contracts. Standard offer contracts facilitate transactions and reduce their costs. Thus, a state that makes standard contracts available to facilities of up to 10 MW will encourage more development of smaller scale projects than states where the limit is 100 kw.

C. Avoided Cost Methodologies

States have adopted a variety of methods for calculating avoided cost based rates for QF energy and capacity. These methodologies can be grouped into five general classifications:

- *Proxy Unit Methodology*: last unit added, next one planned, or hypothetical unit
- *Peaker Method*
- *Difference in Revenue Requirement (DRR)*
- *Market-Based Pricing*
- *Competitive Bidding*

In addition, this section will discuss the methodology for calculating avoided cost rates in the context of energy efficiency programs.

Not only do the methodologies for calculating avoided costs vary from state to state, they also vary *within* a single jurisdiction, depending upon circumstances. Some states such as Oregon use an administratively-calculated avoided cost rate for standard offer contracts but apply a rate determined through competitive bidding for larger contracts. Other states, such as Montana, offer QFs several different methodologies for avoided cost rates.

The chart below summarizes each state's avoided cost methodology. The section that follows will discuss each of these five methodologies generally, as well as the avoided cost methodology for energy efficiency and some of the policy considerations for each choice. Because of the complexity of each methodology, the details of the nine state methodologies covered in this paper (and selected because they are representative of the various avoided cost methodologies) are attached as Appendix A.

Table 1: Avoided Cost Methodologies, Selected States

State	Proxy	Peaker	DRR	Market Rates	Competitive Bidding
MA				Avoided cost based on hourly market clearing price for energy, monthly clearing price for capacity measured by NEISO.	
CA[34]	As available capacity for short-term Ks based on fixed cost of CT as proxy.			Short-term and long-term as available energy contracts based on market index formula & admin determined heat rate. Long-term firm capacity avoided costs based on market price referent.	Effective 8/2011, uses reverse auction for renewables 1.5 MW to 20 MW – companies price and bid their product and utilities select lowest cost. Program is for small renewables, not just QF renewables.
ID	Rates for standard offer contract based on proxy or SAR (surrogate avoided resource) which is a hypothetical gas fired CCCT; previously coal-fired steam plant projects. As of December 2010, standard offer		IRP-based DRR methodology used to set avoided costs for QFs too large to qualify for standard offer contracts.		

[34] Rates on the chart do not apply to CHP as those rates are set by a settlement formula. Settlement rates for QF CHP facilities of less than 20 MW include avoided GHG costs and a modified heat rate.

State	Proxy	Peaker	DRR	Market Rates	Competitive Bidding
	contracts available to wind and solar projects less than 100 kw.				
UT	For resources deficiency periods, avoided cost rates based on proxy plant based on next plant that utility decides to buy or build based on IRP.		Uses DRR during periods of resources sufficiency.		
MT	Two proxy-based rates: (1) rate based on avoided costs or coal-fired plant as proxy or (2) wind only QF rate available using wind plant as proxy.		Competitive bidding sets QF rates for projects larger than 10 MW.	Third option for market-based QF rates is based on market-based acquisition price for coal plant.	
OR	Proxy method used in periods of resource deficiency with CCCT unit as proxy.			Energy-only, market-based QFs available in periods of resource sufficiency.	
NC		May be used by utilities as an option for setting QF rates.	May be used as an option for setting QF rates.		Available for renewable QFs larger than 3 MW that do not qualify for standard rates based on size.
GA					Uses competitive bidding to determine cost of proxy unit.
FL	Utilities' next avoided unit as shown in ten year site plan is used as proxy.				

1. Proxy unit

The proxy method assumes that a QF enables a utility or a region consisting of several utilities to delay or defer a future generating unit. Thus, the utility's avoided costs are based on the projected capacity and energy costs of a specified proxy unit.[35] The proxy unit's estimated fixed costs set the avoided capacity cost and its estimated variable costs set the energy costs. The proxy unit approach is unit-specific and does not depend upon system marginal costs.

Although many states that use the proxy unit method select the proxy as the next identified generating unit in the utility's integrated resource plan (IRP), other proxies are used in some states. For example, the proxy may be a generic statewide unit,[36] a hypothetical or surrogate unit, or some other variant of these approaches. The policy decision to select a proxy unit may reflect competition among different interests: most utilities prefer to select a lower cost CT unit as the proxy, while a QF ownership interest may favor a higher cost baseload unit.

The proxy methodology is generally regarded as the simplest of the avoided cost methodologies because it relies on data for a specific plant design.[37] Perhaps for that reason, it remains the dominant methodology, as shown by the sampling in Appendix A.

There are, however, drawbacks to the proxy model which can give rise to inconsistencies. With a proxy methodology, the choice of unit can drive avoided costs. For example, one commenter notes that one reason that accounted for higher PURPA rates following its enactment (in addition to inaccurate estimations about the rising energy costs) is that rates were based on more expensive baseload plants such as coal or (in the case of Maine), nuclear plants. Thus, using lower cost plants (or least cost plants, as determined by the IRP) as

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[35] *PURPA: Making the Sequel better Than the Original*, The Battle Group (prepared for Edison Electric Institute)(December 2006) at 9, online at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/purpa.pdf.

[36] The choice of a peaking plant as a proxy unit should not be confused with the "peaker" methodology, described infra, which bases avoided cost on displacement of marginal generation rather than displacement of a plant.

[37] *See, e.g.,* Vanderlein, *Bidding Farewell to the Social Costs of Electricity Production: Pricing Alternative Energy Under the Public Utility Regulatory Policies Act*, 13 J. Corp. L. 1011 (1988).

proxy units will reduce avoided costs.

2. Peaker

The peaker method assumes that a QF, rather than displacing or delaying the need for a particular generating unit, allows the utility to reduce the marginal generation on its system and avoid building a peaking unit (typically, a combustion turbine (CT)).[38] Under the peaker methodology, the capacity component of the avoided cost is based on the annual equivalent of the utility's least-cost capacity option, which is typically a CT.

The energy component of the avoided cost is based on actual or forecast marginal energy costs over the life of the contract. The peaker method assumes that the QF output displaces the marginal or most expensive generation source available for dispatch over the duration of the contract. Marginal energy costs may be calculated on an hourly or longer period. A production cost simulation is used to estimate these system marginal energy costs with and without the QF in the portfolio.[39]

Utilities favor the peaker approach because these units have lower capital costs and therefore minimize avoided capacity costs. Utilities contend that the peaker methodology will produce long-term costs that are equivalent to baseload. Although under the peaker methodology, capacity costs are lower (since they are based on the equivalent of the utility's least-cost capacity option), energy costs are based on the marginal cost of the most expensive generation source dispatched throughout the year. Utilities reason that lower capacity costs plus more expensive marginal energy costs are equivalent to the higher capacity cost of baseload plus lower fuel costs.

The Georgia Commission, however, rejects this rationale – or at least, found that the peaker methodology alone is inappropriate for renewable QFs. The Georgia Commission pointed out that the peaker methodology has low capacity costs, and assumes that a project will "make all of its money" on energy payments which are variable. However, the Georgia Commission noted that "financing is not available for a project with a revenue stream solely dependent

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[38] *PURPA: Making the Sequel Better Than the Original* , *supra* at 10.

[39] *Id.*

upon energy payments that vary by the hour." The Georgia Commission did not require a change in the methodology, but instead, required the utility to revise its avoided cost formula to reflect non-price factors which are "not neatly classified as capacity and energy." The revised formula included benefits such as increased reliability of locally produced fuel source, reduced transmission and distribution costs, reduced need for pollution control systems and the value of environmental credits earned for the use of power generated using renewable fuel.[40]

For avoided energy costs the formula is displayed as follows (emphasis added for avoided environmental and start up costs):

avoided energy cost =
(territorial system lamda)*(Marginal cost multiplier)*(Average fuel portfolio/spot gas portfolio)
+ avoided O&M + *avoided environmental costs + avoided start-up costs*

3. Differential Revenue Requirement (DRR)

The differential revenue requirement, or DRR, essentially calculates the difference in the utility's overall generation cost with and without QF capacity. There is a linkage between DRR and a utility's IRP. The QF capacity reduces the utility's revenue requirement and the avoided costs are equal to the present value of the difference in total generation costs with and without QF power. According to one expert witness in a Utah proceeding, the "most theoretically" correct approach to using the DRR method is to develop two IRP resource plans – one which reflects inclusion of the QF and the other which does not. [41]

As with the other methodologies, the DRR approach offers pros and cons. The DRR approach is regarded by some commentators as capable of producing the most accurate results, and the availability of more sophisticated modeling tools makes the DRR approach more accessible than it was when PURPA was enacted.[42] Still, the DRR method often comes under criticism because of lack of transparency since the utilities have access to the models and

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[40] *Petition of Biomass Gas & Electric Regarding Forsyth County Renewable Energy Plant*, Docket No. 4822-U, (Georgia Public Service Commission 2004).

[41] Testimony of Philip Hayet at 6, Re: PacifiCorp Application for Approval of IRP Based Avoided Cost Methodology for QFs Docket No. 03-035-14 (2005).

[42] *Id.*

input data. In addition, the DRR methodology is more appropriate as a short-term rather than long-term methodology because it assumes that QFs are perpetually a marginal resource on the utility's system.

Perhaps because of perceived difficulty, the DRR approach has been used in only a limited number of jurisdictions. North Carolina does not mandate DRR, but permits its utilities to use it in calculating biennial avoided costs. Utah requires DRR use for periods of resource sufficiency.

4. Market-based pricing

States adopt market-based QF rates primarily for two reasons. First, market-based rates reflect recognition that markets are sufficiently competitive such that QFs can participate. Second, market-based rates are usually available for energy (or short- term capacity) when a utility has sufficient or excess capacity, and thus does not need to make any capacity purchases to meet system reliability standards. Both Massachusetts (see Appendix, discussion) and Maine, which are within the Northeast ISO, base QF rates on capacity and energy sales within the ISO footprint.

In cases where a wholesale market exists for both capacity and energy, utilities in the region have, or generally will qualify for relief from PURPA, at least with respect to purchases from QFs of 20 MW or more. However, the availability of an RTO-operated market is required for those states charging market-based rates.

5. Competitive bidding

a. Existing programs

In some states, utilities are permitted or required to use competitive bidding to establish avoided cost rates. Though the details vary, generally competitive bidding is implemented as follows. First, a utility determines its need for power through the IRP process. Based on the IRP process, the utility may establish a benchmark price and allow companies to bid to meet it, or it may conduct a competitive bid and select resources based on the criteria established in its request for proposals. The winning bids are regarded as equivalent to the utilities' avoided cost because they reflect the price at which the utility could otherwise procure power but for the QF.

Although most QF rates were administratively determined after PURPA passed, states and FERC began considering the competitive bid option a decade later. In 1988, FERC proposed a rule that would have expressly endorsed competitive bidding as a way to set avoided costs, explaining that this would result in more competitive rates and reward those QFs that could produce power more efficiently and at a lower cost.[43] FERC's proposed rule also explained that competitive bidding offers an alternative to the complexity of administratively determined avoided cost rates and is consistent with trends towards competition in the power industry.[44]

However, for some smaller QFs participation in the competitive bidding process could produce rates that are too low to make projects viable. This was true in particular after FERC's decision in *Southern California, supra*, where FERC required all-source bidding, thereby pitting renewable QFs against potentially less expensive power sources. Now that FERC has overruled *Southern California*, and sanctioned sole-source avoided cost rates, there may be opportunities for QF-only, or even technology-only competitive bid processes which may produce more favorable QF rates.

b. Emerging competitive bidding: reverse auctions

Though not specific to PURPA, a new version of competitive bidding -- California's newly adopted reverse auction mechanism (RAM) -- bears mention because it serves as a related policy tool for encouraging renewable development. In August 2011, the California Commission issued rules for its RAM program.[45] The RAM does not replace PURPA; the California Commission specified that its existing QF program will remain in effect, and further, that it was adopting the RAM program pursuant to its authority under state law and not under PURPA.

The RAM program works as follows. California's utilities are required to procure 1000 MW (collectively) of renewable power using the RAM through auctions that will be held two times per year. To participate in the RAM program, renewable energy sellers submit price bids to the utilities during the auctions. The program is open to renewables between 1 and 20 MW. In addition, sellers must show that they have made substantial progress with California

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[43] *Administrative Determination of Full Avoided Costs, Sales to Qualifying Facilities, and Interconnection Facilities*, 53 FR 9331 (1988), FERC Stats. & Regs. ¶ 32,457 (1988) (ADFAC NOPR).

[44] *Id*; See also Order Terminating Docket, 53 FR 51310 at 51312 (1998).

[45] The rules are available online at : http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/141795.PDF.

Independent System Operator (CAISO) on interconnection to be eligible to compete in the auction.

The utilities then select the projects with the lowest price first. Once a bid is selected, the seller and the utility execute a standard power purchase agreement with a term of 10, 15, or 20 years which incorporates the seller's bid price. Winning projects are required to achieve commercial operation within 18 months of approval of the contract by the California Public Utilities Commission (CPUC), with one six month extension allowed. The first auctions will take place in fall 2011 and spring 2012.

6. Avoided cost pricing for energy efficiency programs

The avoided cost concept is also applied for the purposes of evaluating the benefits of energy efficiency programs. In approving an energy efficiency program, states must evaluate the anticipated costs and benefits. The avoided cost concept plays into the anticipated benefits side of the equation since those costs that a utility avoids as a result of energy efficiency – such as purchases of energy and capacity, emissions and others – represent the benefits of the program.[46]

The benefits of energy efficiency programs are generally determined by calculating the avoided costs of energy and capacity associated with installation of certain measures or application of certain practices included in an energy efficiency program.

- Energy savings associated with a measure or practice are forecast through the lifetime of the measure.
- Participation rates are calculated or forecast based on program data or plans.
- A "net-to-gross" ratio is applied to the total energy savings reflecting deduction of energy savings that would have occurred without the program (free riders) and addition of additional energy savings induced by the presence of the program (free drivers).[47]

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[46] *Understanding Cost Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy Makers* (November 2008)(a resource of the National Action Plan for Energy Efficiency).

[47] For example, a CFL bulb coupon may be used by a customer who already planned to purchase a bulb (free rider). It may also be used by a customer who needs two bulbs, with the second bulb purchase being induced by the coupon for the first (free driver).

- Avoided costs resulting from efficiency programs are calculated based on an approved state method, usually similar to or identical to the method used for the QF rates.
- Net present value of the avoided costs is calculated.
- If authorized, additional avoided costs are added, such as cost of avoided CO_2 emissions or reduced costs of compliance with renewable portfolio standards (RPS).[48]

While this general method is adopted widely, it is worth noting that several experts have questioned common practices that define the benefits of energy efficiency narrowly as avoided costs, but define the costs more broadly.[49] In other jurisdictions, energy efficiency resources are considered as resources on an equivalent basis to supply side resources, and avoided costs are not a primary tool for resource evaluation.[50]

Several states, including California and Florida, have adopted an avoided cost methodology for energy efficiency that takes into account a broader spectrum of costs – such as avoided CO2 emissions and (potentially) avoided RPS compliance costs – than the QF calculation, which looks more narrowly at the costs of avoided energy and capacity costs. As discussed, FERC limits consideration of environmental externalities to those that are actual rather than hypothetical costs because PURPA requires that rates be based on actual costs avoided. PURPA, however, does not apply to state's energy efficiency cost-benefit analyses. Thus, states are not similarly constrained from taking account of possible, but not actual, costs that may be avoided through energy efficiency programs.

7. Comparison of methodologies

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[48] An overall reduction of energy purchases through energy efficiency programs reduces the amount of renewables that a utility must purchase for RPS compliance.

[49] Neme, Chris and Marty Kushler, *Is It Time to Ditch the TRC? Examining Concerns with Current Practice in Benefit-Cost Analysis*, ACEEE Summer Study on Energy Efficiency in Buildings, 2010.

[50] Eckman, Tom, *Some Thoughts on Treating Energy Efficiency as a Resource*, Electricity Policy.com, 2011.

As discussed, each avoided cost methodology comes with pros and cons, summarized in the chart below:

Methodology	Pros	Cons
Proxy	Simple and transparent	May overstate costs if proxy selected does not match operating characteristics of QFs Avoided costs heavily dependent upon selection of proxy (with higher cost units resulting in higher avoided costs)
Peaker	Least cost option due to lower capacity costs of peaker units	Avoided costs not sufficient for financing QFs since higher energy prices may not counterbalance lower capacity over life of project
Differential Revenue Requirement	More sophisticated and complex methodology likely to produce most accurate avoided cost calculation	Overly complex and lacking in transparency and accessibility Assumes that QF is always a marginal resource
Market-based rates	Simple and least cost Treats QFs as competitive resource	Not always high enough to cover QF costs or incentivize QF development
Competitive bidding	Least cost option; allows utility to select among offered resources for its system	Participation in competitive bidding can be complicated for QFs Rates not high enough to support QF development
Energy Efficiency avoided costs	Usually takes account of all costs avoided, including externalities	Formula may differ from PURPA, as it estimates savings, rather than rates (as in PURPA)

As noted, it was not possible to develop a model to compare which methodology will yield the most favorable avoided cost rates due to inaccessibility of utility data. Utilities have broad discretion over many of the assumptions that go into determining avoided costs in any of these models. An example follows:

1. Utility A excludes all third party power purchases from avoided cost calculations if the purchase lasts for more than 1 hour (example: Utility A knows this afternoon will be tight on generation, so it purchases

a 2 hour block of generation) - this purchase is excluded from avoided cost calculation because it is over 1 hour.

2. Utility B excludes natural gas transportation reservation charges from calculations because these are longer that 1 hour.

3. Utility C's average fuel expenses charged to consumers over a calendar year are always higher than the yearly simple average of avoided cost payments made to qualifying facilities (i.e. a customer who operates a 1 MW load steady for 8760 hrs/year pays more for fuel in his electricity bill than a QF gets paid for 1 MW steady generation for 8760 hours/year).

4. Utility D uses its third party power purchase price (for a 1 hour purchase) in the avoided cost calculation, even if the variable cost of operating the most expensive Utility D owned generating plant during that same hour exceeds this purchase price.

One reviewer commented that "these sorts of random judgment calls are depressing avoided cost rates in Florida" which were less than $37/MWh for calendar year 2010 and less than $36/MWh for calendar year 2011. However, unless a state utility commission decides to assign exact cost values to be input into avoided cost calculations (somewhat analogous to the surrogate avoided resource (SAR) methodology in Idaho, which involves a hypothetical proxy unit), this element of randomness will always be inherent in avoided cost ratemaking – which is one of the drawbacks of PURPA. Perhaps if a state were to adopt technology-specific avoided cost rates, there would be more uniformity in the underlying cost assumptions.

There are many other factors than a state's choice of avoided cost methodologies that influence QF rates or incent development. For example, FERC's regulations only require standard offer contracts for QFs less than 100 kw. In jurisdictions where standard contracts are available to QFs up to 10 or even 20 MW, increased QF development can be expected.[51] Likewise, an avoided

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[51] In California, a state which has had significant QF development activity, standard offer contracts are available to QFs up to 20 MW. In Idaho standard offer contracts were available to wind and solar projects up to 10 MW – which triggered significant wind development (in part because wind companies might develop larger projects as separate 10 MW units to take advantage of standard offers). The Idaho Commission discontinued the availability of standard contracts to wind and solar projects larger than 100 kw because of excess development and increased costs for ratepayers. See Power Gen Worldwide, http://www.powergenworldwide.com/index/display/wire-news-

cost methodology which results in a lower rate may be counterbalanced by a policy which allows QFs to own renewable energy credits (RECs) which can generate an additional stream of revenue for the project.

The following sections identify some of the other factors that impact QF rates paid to QFs in addition to the choice of methodology.

D. Resource Sufficiency versus Resource Deficiency

The question of resource sufficiency arises regardless of which of the five methods described above is used by the state. Some utilities argue that when there is surplus generating capacity, the only avoidable costs to be considered are avoidable energy costs: the cost of existing capacity has already been incurred and thus, cannot be avoided (and therefore, is equal to zero).

Following this resource sufficiency argument, some states, such as Georgia, do not require utilities to make long-term capacity payments when they have no capacity needs as determined by the IRP.[52] Similarly, North Carolina does not require payment of capacity credits where a utility has excess capacity. The utility's capacity needs are determined as of the time the QF commits to sell and not when the negotiations are completed or the contract is executed.

This reasoning is also followed in California in a slightly more complex process. Utilities can decline to offer a contract (either for short-term as-available capacity, or long- term capacity) to QFs larger than 20 MW if the utility can demonstrate that it does not need the capacity. However, for QFs smaller than 20 MW, a utility may only deny capacity contracts if the total capacity of the utility's contracts for QF power would exceed 110 percent of the utility's own capacity.[53]

Other states do not relieve utilities of their obligation to make capacity payments even during times of surplus. These states reason that utilities are *always*

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display/1433525969.html (June 11, 2011).

[52] *See* Docket 4822 and Georgia Power Point Presentation, *supra.* (no capacity payments required when utilities have no capacity needs, as determined by IRP.)

[53] Opinion on Future Policy and Pricing for Qualifying Facilities, Decision 07-09-040, California Public Utilities Commission, (September 20, 2007).

planning capacity additions – and that even in periods of resource sufficiency, QF purchases may enable a utility to defer an addition for several more years even if the purchases will not avoid a unit entirely.[54] FERC itself has suggested, in the Preamble to its PURPA rules, that capacity credit may be warranted when a QF's contribution allows a utility to defer or avoid additional plant construction or future firm power purchases.

Other states have two distinct approaches for calculating avoided costs in resource deficiency and sufficiency periods. Oregon uses integrated resource planning (IRP) to demarcate periods of deficiency and sufficiency.[55] In periods of resource sufficiency, avoided monthly on- and off-peak forward market prices, as of the utility's avoided cost filing, are used to calculate avoided costs. For periods of resource deficiency, Oregon's avoided cost rates reflect the variable and fixed costs of a natural gas-fired combined cycle combustion turbine (CCCT).[56]

In Utah, during periods of resource sufficiency, avoided costs are determined using the differential revenue requirements method. This is done by evaluating system energy costs with and without the addition of a 10 MW, zero-cost resource. [57] Capacity payments are based on the fixed costs of a simple cycle combustion turbine (SCCT) proxy resource for months during the resource sufficiency period in which the utility is capacity deficient and the utility plans to purchase this capacity.

During the period of resource deficiency, Utah bases avoided capacity and energy costs on the proxy method. Avoided capacity and energy costs are developed from the expected costs of resource(s) the utility plans to build or buy based on its IRP, and which are avoidable or deferrable. For the most recent

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[54] Vanderlinde, *Bidding Farewell to Social Costs*, 13 J. Corp. L. at 1025 (discussing issue of treatment of capacity payments in cases of excess capacity).

[55] 242 P.U.R.4th 140.

[56] *Id* at *68. The Oregon Commission's avoided cost methodology does not apply to Idaho Power. Because Idaho Power serves Idaho, it must use a surrogate avoided rate (SAR) model that does not distinguish between sufficient and deficient periods. Thus, the Oregon Commission granted an exception, for administrative convenience, to permit Idaho to use the SAR methodology for avoided cost rates.

[57] Docket No. 09-035, 2009 Utah PUC LEXIS 420 (2009).

proceeding, Utah selected a CCCT.[58]

E. Dispatchability and Minimum Availability as a Precondition to Capacity Payments

FERC permits states to consider a resource's dispatchability in setting avoided cost rates. Because small QFs are often renewable energy resources, they may operate in a different manner from fossil-fueled plants. However, the utility will not get all of the benefits typically associated with the higher capacity cost of an intermediate or baseload unit if the QF does not operate the same as the avoided resource would have operated (which of course can only be simulated). Some states choose to address this potential problem by allowing the utility to establish price and/or performance requirements within the contract or to retain a high level of discretion in the project's dispatchability.

Although utilities may penalize QFs for lack of dispatchability through contract performance requirements, our research did not uncover any examples where a contract or avoided cost calculation recognizes the ability of resource such as wind to be rapidly dispatched downward to follow load drops. The system benefit of such downward dispatches is that the system may reduce costs through greater use of resources that may be more undesirable (operationally or economically) to dispatch downward. FERC's regulations would allow consideration of the system benefit of downward dispatchability in avoided cost rates; however, this approach has apparently not been adopted in any state. Instead, it is far more common for utilities to propose a methodology that penalizes QFs for lack of dispatchability and for states to approve these proposals.

Penalties for inadequate unit availability are primarily found in the Southeast. Georgia allows for capacity payment adjustments to ensure alignment between QF and proxy resource availability.[59] For example, Georgia Power currently offers several standard offer contract options to QFs of 30 MW or less.[60]

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[58] *Id.*

[59] *Petition of Biomass Gas & Electricity*, 2004 Ga. PUC LEXIS 43 (2005).

[60] Georgia Power Presentation on QF Rates (2010), online at www.georgiapower.com/smallproducers/small_power_producers.pdf. Georgia Power has projected that its capacity needs through 2014 are met, so it will not hold an RFP for additional capacity. When an RFP is conducted, projects of 5 MW or greater must bid, and standard offer is available to projects 5 MW or

Two of the standard options require QFs to operate at a minimum 90 percent availability to receive full capacity payments; otherwise the payments are prorated. A third standard option, known as the "proxy option" requires a QF to guarantee a seasonal availability percentage (SAP) of 96 percent. If the SAP falls between 96 percent and 60 percent, then the weighted capacity payment for the season is reduced by 1.5 percent for each 1 percent drop below 96 percent. If the SAP falls below 60 percent, a QF forfeits capacity payments for the season.

Florida's regulations allow utilities to impose dispatch and minimum capacity availability requirements.[61] Thus, a Florida utility may include provisions in a QF contract which require the QF to meet or exceed the minimum performance standard of the selected avoided unit and maintain a minimum monthly availability factor to qualify for full monthly capacity payments.[62]

Outside the Southeast, it does not appear that states apply automatic penalties for availability that is below a proxy or peaker standard. For example, Idaho's avoided cost methodology has never accounted for a proxy's (or SAR) dispatchability or capacity availability. The Idaho Commission explains that accounting for these characteristics would be difficult given the wide diversity of QF resources.[63] The other states reviewed either do not include minimum capacity availability requirements, or at least do not reduce capacity payments to zero where a QF fails to meet the capacity availability requirements.

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smaller.

[61] *See* FAC 17.0832.

[62] *See, e.g.,* Tampa Electric Company, Rate Schedule COG-2, Appendix C, Docket 07023-Q (filed April 2, 2007). The contract states: Energy provided by CEPs shall meet or exceed the following MPS on a monthly basis. The MPS are based on the anticipated peak and off-peak dispatchability, unit availability, and operating factor of the Designated Avoided Unit over the term of this Standard Offer Contract. The QF as defined in the Standard Offer Contract will be evaluated against the anticipated performance of a combustion turbine starting with the first Monthly Period following the date selected in Paragraph 6.b.ii of the Company's Standard Offer Contract. The basis for monthly capacity payments is a 90 percent monthly availability factor with no payments for availability below 80 percent. For monthly capacity between 80 and 90 percent, monthly capacity payments are equal to BCC (base capacity credit) x .02 (monthly capacity factor) x contracted capacity.

[63] 2010 Ida. PUC LEXIS 215 at *18.

F. Line Loss and Avoided Transmission Costs

In addition to avoiding the cost of energy and capacity, QFs may also enable a utility to avoid line losses (*i.e.*, the volume of electricity lost as it travels from source to load) and transmission costs where a QF is located in closer proximity to load. FERC's regulations provide that to the extent practicable, QF rates should reflect the costs or savings resulting from line losses and avoided transmission costs.[64]

The impact of line loss adjustments cuts both ways, depending upon the QF's proximity to transmission and load. Many states that account for line losses acknowledge that they may require an upward or downward adjustment to rates. Montana includes line losses in rates to ensure ratepayer neutrality – i.e., that ratepayers will not be any better or worse off when the utility buys from the QF. Utilities must submit cost data to support avoided costs and loss line adjustments, with determinations on a case by case basis.[65] In Massachusetts, energy avoided cost prices for QFs are adjusted up or down to reflect line losses in accordance with NEPOOL.[66] Oregon's avoided cost rates reflect line loss adjustments, avoided transmission costs and integration costs. The Oregon Commission also adjusts avoided cost rates for wind to reflect integration costs. For the first year, integration costs are based on the actual level of wind resources in the control area, plus the proposed QF. For years two through five, costs are based on expected level of wind, including any new resources. Integration costs are then fixed at the five year level and adjusted for inflation for the remainder of the life of the contract.[67]

California adjusts short-run avoided costs (SRAC) to reflect the difference between the utility's line losses when it purchases QF power and what the losses would have been in the absence of a QF purchase. California derived line losses (or what it terms "transmission loss factor") based on the generation meter multiplier (GMM) methodology used by CAISO to determine line losses for sales into the CAISO system. [68] The appropriate adjustment is equal to the difference between GMM for QF line losses and the GMM for system average losses

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[64] 18 CFR § 292.305(e)(4).

[65] 100 MPSC,Order No. 7068b, ¶84.

[66] Massachusetts Regulation 8:05.

[67] Order No. 07-407, 2007 Ore. PUC LEXIS 32.

[68] *Id.*

without QFs. In 2009, CAISO stopped using the GMM to measure line losses for sales into its system but nevertheless, the California Commission determined that it would continue to calculate GMM-based energy line losses on a monthly basis for different categories of QFs.[69]

Other states, however, do not account for line losses or transmission costs for various reasons. Though Idaho includes avoided transmission costs, it generally sets the value as zero because the SAR is a CCCT and the assumption is that it would be located close to load.[70] Utah has preliminarily suggested the line losses are not appropriate for non-firm power like wind which will need back up and thus, a utility does not really avoid line losses.

Finally, in states that use competitive bidding or some market-based methodology, it is assumed that line losses and transmission costs will be reflected in the price paid. In Georgia, where avoided cost rates for some projects are determined by competitive bid, the transmission costs will impact how the company ranks the bids and thus, will essentially be reflected in the eventual rate.[71] Although California does include line losses, the California Commission has explained that once markets are fully competitive, line loss calculations will be reflected in market-based energy prices. The quantity of power that a QF commits to deliver will be adjusted for line losses, and the market price will reflect either a larger or smaller quantity of power depending upon the extent of the line losses.[72]

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[69] Re: PG&E, Granting Petition to Modify Decision, Decision 01-01-007, (May 26, 2009)(affirming use of GMM methodology to adjust short run avoided costs).

[70] *In Matter of Review of the SAR Methodology for Calculating Published Avoided Cost Rates,* 2010 Ida. PUC LEXIS 215 (2010). In this same order, the Idaho Commission proposed a wind SAR which would use a wind plant rather than a CCCT as a proxy unit. Because wind can be located anywhere within Idaho and four surrounding states, the utility would avoid transmission costs by purchasing from a QF. Thus, the Idaho Commission proposed to include transmission costs as a component of the wind SAR, based on the utilities' average embedded transmission costs. *Id.* The proposed wind SAR remains pending as of the date of this Report.

[71] *Petition of Biomass Gas & Electricity*, 2004 Ga. PUC LEXIS 43 (2005)(allowing for capacity payment adjustments to ensure alignment between QF and proxy resource).

[72] *Id.*

G. Externalities and Environmental Cost Adders

Externalities and environmental adders are not common features of avoided costs, but some states have made allowances. FERC allows states to include externalities or adders to reflect, for example, emissions allowances or costs so long as those costs are not speculative but are actually avoided by the QF. Some states have done so, while others have not. By contrast, on the energy efficiency side, the avoided cost calculation (for assessing program costs and benefits) often reflects environmental considerations, such as the cost of avoiding carbon emissions.

A typical state that does not include any externality cost adders in PURPA avoided cost rates is North Carolina. According to the North Carolina Utilities Commission (NCUC), costs associated with externalities in standard offer avoided cost rates are not included because utilities do not pay a fee or other monetary charge reflecting the environmental impact resulting from the use of the facility that can be avoided by purchasing power from a QF instead.[73]

Other states provide statutory or regulatory permission for consideration of externalities and environmental adders, but have not put those policies into practice. Over 20 years ago, Florida approved inclusion of a standard offer contract language that recognizes emissions cost savings of renewables. The clauses serve as a placeholder which would allow for inclusion of emissions allowance benefits once a value has been placed on them.[74] However, it does not appear that this practice has been put into effect in any actual contracts.

A few states do include an adder to reflect externalities and environmental costs in the QF rates. Georgia allows a five percent adder in QF avoided costs for renewables to reflect environmental and societal externalities associated with renewables development. The five percent adder has its origins in Georgia's competitive procurement. When utilities conduct a competitive bid, a five percent adder is included in the value of all bids when comparing them to the renewable's bid (this applies to both QF and non-QF renewables). Using this approach, the renewable resource has an advantage for non-price factors that can make it a winning bidder. Where a QF wins because of the 5 percent advantage,

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[73] *Biennial Determination of Avoided Cost Rates*, Docket No. E-100, North Carolina Utilities Commission, 2007 N.C. PUC LEXIS 1786 (December 2007).

[74] Docket No. 910004-EU, Order No. 24989, Florida Public Service Commission, 1991 Fla. PUC LEXIS 1386, 91 FPSC 8 (August 29, 1991).

the price that it receives must reflect the adder because the cost of the bid that was replaced may be too low to be viable for the QF to accept.[75]

By contrast, Georgia has declined to include an adder to reflect environmental costs of complying with impending regulations on power plant emissions. Georgia reasoned that the cost of complying with environmental regulations would be included in a bidder's price and that inclusion of projected costs was speculative.[76]

In some instances, environmental costs may be reflected indirectly in avoided cost rates. For example, if a coal plant is selected as a proxy unit and it has invested in equipment for purposes of emissions reductions or environmental compliance, those added expenses are rolled into the overall cost and would thus be reflected in calculation of avoided cost rates.

H. Long-Term Levelized Contract Rates versus Varying Rates

Levelized rates are fixed over the life of a contract, essentially resulting in overpayment in early years and underpayment in later years. Non-levelized rates vary with the cost of fuel. Idaho views levelized rates as providing an incentive to QFs and requires utilities to offer both levelized and non-levelized contract rates.[77] Florida also requires utilities to offer the option of levelized rate contracts.[78]

Other jurisdictions, while recognizing that levelized rate contracts provide incentives to QF development, have considered whether long- term levelized contracts can result in overpayments and stranded costs.[79] While recognizing some of the risks of levelized rates, North Carolina refused to eliminate levelized contracts entirely, finding that doing so would have negative effects on programs

[75] *Id.*

[76] *Petition of Biomass Gas & Electricity*, 2004 Ga. PUC LEXIS 43 (2005).

[77] *In The Matter of the Application of Idaho Power Company for Approval of a Firm Energy Sales Agreement for the Sale and Purchase of Electric Energy between Idaho Power Company and Payne's Ferry Wind Park*, Case IPC-E-0-20, Order 30926 (October 8, 2009).

[78] FAC 25-17.0832 (f)(3).

[79] *Biennial Determination of Avoided Cost*, 2003 NC PUC LEXIS 1232 at1235 (evaluating whether to continue to require levelized rates).

to encourage facilities fueled by trash or methane from landfills or hog wastes. Thus, North Carolina requires utilities to offer 5, 10 and 15- year levelized rate contracts to small hydro QFs contracting to sell 5 MW or less of hydro and non-hydroelectric QFs contracting to sell 5 MW or less that are fueled by trash or methane from landfills or hog waste. They should also continue to offer 5-year levelized rates to all other QFs contracting to sell 3 MW or less.[80] North Carolina concluded that limiting the availability of levelized QF contracts would allow the state to continue to enhance the feasibility of small power facilities, while minimizing utility risk of overpayment. Florida also requires levelized contracts.

Other jurisdictions such as Virginia conclude that longer- term, levelized contracts are not appropriate in a competitive market because they may lock utilities (and their ratepayers) into contracts for unnecessary capacity. [81] California also observed that long- term, levelized rate contracts blur economic signals regarding a utility's continued need for capacity, particularly at times when the value of additional capacity is low.[82]

I. REC Availability

State policies vary on whether a QF or a utility owns a REC in the absence of a contractual provision assigning ownership.[83] As a general matter, permitting QFs to retain RECs and sell them separately from project power provides an additional stream of revenue which can make some projects more viable. REC ownership can also give QFs an additional bargaining tool in

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[80] *Id.*

[81] See, e.g., *In re Application of Appalachian Power Co.,* Case No. PUE970001, 1998 WL 67087 (Va. State Corp. Comm.) (holding that long-term avoided costs have no validity in market environment and shortening commitments to purchase capacity provides incentive for electric utilities to minimize potential for stranded costs).

[82] *Second Application of PG&E for Approval of Standard Offer*, 1987 Cal. PUC LEXIS 349 (finding levelization requirement of Standard Offer 2 troublesome when value of additional capacity is low and declining to approve continuation of SO-2 contracts).

[83] *Who Owns Renewable Energy Certificates: An Exploration of Policy Options and Practice*, Ed Holt, Ryan Wiser, Mark Bolinger, LBNL-59965, Lawrence Berkeley National Labs (April 2006) (summarizing 26 state policies on REC ownership) online at eetd.lbl.gov/ea/emp/reports/59965.pdf.

situations where they must negotiate rates. On the other hand, some have argued that allowing QFs to retain RECs deprives ratepayers of the benefits of REC sales.

Florida's regulations grant QFs the right to REC ownership and to sell RECs separately from power sales – though there is no discussion of the reason for this policy choice.[84] Iowa determined that a QF was not required to convey RECs as part of a contract with a utility because of FERC's holding that avoided cost rates compensate a QF only for power and not for environmental attributes of the project.[85] In Montana, QFs that avail themselves of a wind-based avoided cost rate must convey RECs to the utility. Because the wind-only rate relieves QFs of the obligation to self-supply regulating reserves or purchase them from the utility, QFs must convey their RECs to Northwestern Energy (NWE) – presumably as a trade-off for the more generous wind rate.[86]

J. Resource Differentiation

Some states make available different QF rates or contracts to encourage development of certain types of resources. For example, as just discussed, North Carolina offers long- term levelized rates to waste- to- energy facilities to encourage their development. In an effort to encourage additional wind, Montana approved three different wind-only standard QF rate options offered by NWE.[87]

Idaho has two separate standard contract rates – for fueled and non-fueled projects. (Fueled and non-fueled are terms of art; fueled projects are those that are fossil-fueled while non-fueled projects are renewables).[88] In addition, Idaho

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[84] *In re: Petition for approval of amended standard offer contract and retirement of COG-2 rate schedule, Progress Energy Florida*, 2009 Fla. PUC LEXIS 926, *; 279 P.U.R.4th 561 (November 2009).

[85] *Midwest Renewable Energy Projects v. Interstate Power & Light Company*, Iowa Utilities Board, 2009 Iowa PUC LEXIS 2.

[86] Montana Public Service Commission, Order No. 6973d (2010).

[87] MPSC, Order No. 6973d (2010)(describing various wind options, including short and long-term, as well as rate that reflects added integration charges).

[88] *In the Matter of Petition of Idaho Power for Declaratory Order*, Order No. 28945, Case No. IPE-01-37 (2002).

has proposed a wind-only rate based on a wind SAR.[89] The wind-only SAR would reflect characteristics unique to wind, such as intermittency/reduced dispatchability; likelihood that wind will be located further from load (and thus require additional transmission); and wind's ability to avoid emissions costs that may eventually be imposed on fossil fuel plants. The Idaho Commission has not yet issued a decision on the proposed wind-only SAR.

As discussed in n.20, *supra*, California's three utilities have implemented a special CHP QF rate pursuant to the terms of a settlement agreement by which the parties agreed not to oppose the utilities' request to FERC to terminate their mandatory purchase obligation for projects larger than 20 MW. [90] In June 2011, FERC approved the request, and thereafter, the QF CHP settlement rates took effect. The settlement rates reflect the cost of avoided greenhouse gas (GHG) emissions and include a negotiated heat rate that is more favorable to CHP than the heat rate used for standard QF avoided cost calculations.

Overall, resource- specific QF rates are still somewhat unusual, perhaps because of uncertainty created by FERC's earlier policy prohibiting avoided cost rates based on a QF-only bid process.[91] FERC's recent decision in *California Public Utilities Commission, supra*,[92] now makes clear that resource-differentiated rates (for all QF contracts, not just standard contracts) are permissible. Thus, states seeking to promote development of certain types of renewables may adopt resource-specific QF rates.

IV. FINDINGS AND CONCLUSION

States use a variety of methodologies to determine avoided costs. State policymakers appear to have chosen policies based on several motivations,

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[89] *In the Matter of Review of the Surrogate Avoidable Resource Methodology*, 2010 Ida PUC LEXIS 215 (October 2010).

[90] *See* Decision 11-03-051; Application 08-11-001; Rulemaking 06-02-013; Rulemaking 04-04-003; Rulemaking 04-04-025; Rulemaking 99-11-022, 2011 Cal. PUC LEXIS 184 (March 24, 2011).

[91] *Southern California Edison*, *supra* n. 9, 70 FERC ¶ 61,215 (1995), *aff'd rehearing,* 71 F.E.R.C. P61090 (1995).

[92] *See* n. 10 supra.

including ratepayer neutrality, least cost, and accuracy, or to provide incentives for development of certain types of renewables.

These policy choices have the potential to significantly impact regional markets for alternative power, including renewable energy and cogeneration, as well as the outcome of evaluations of cost-effectiveness of energy efficiency measures. Unfortunately, there is no available model to quantitatively compare the impact of certain methodologies (e.g., proxy unit v. market pricing) or other factors (such as use of resource sufficiency/deficiency) on these markets and related economic evaluations. As noted, development of such a model was not feasible due to differences in state methodologies (making apples-to-apples comparison impossible) as well as lack of cost data to use in modeling.

This report recommends FERC, with input from stakeholders, develop a model for measuring the impact of various methodologies on avoided cost rates. The recommended quantitative model should synthesize the varied ways that states implement avoided costs and provide an evaluation of those methodologies best suited to carrying out PURPA's goal of promoting development of alternative power, including renewable energy and cogeneration, without adverse impacts to ratepayers. Furthermore, the model should be explicitly designed to determine appropriate ways to estimate the benefits of energy efficiency and customer-owned and sited distributed generation for purposes of resource planning, cost-effectiveness evaluations, and similar analyses. FERC is the appropriate agency to undertake this task, because FERC is charged with responsibility for implementing the rules that govern avoided cost ratemaking at the state level and has the ability to access the utility data necessary to conduct the analysis. Most importantly, because FERC does not actually set avoided cost rates, it does not have a vested interest in one methodology over another and thus, is best suited to undertake a neutral review of the various state systems.

Even without the results of a model, however, there are many opportunities for states to set avoided cost rates in a manner that is more reasonable and favorable to advancing CHP and small renewable projects. As this report discussed, FERC's recent decision in *California Utilities Commission* allows states to set resource-specific avoided cost rates – for example, using a wind project as a proxy for avoided cost payments to wind. Resource-specific rates will more closely align with the capital structure and dispatch features of various renewable and cogeneration projects.

Moreover, states can also account for avoided environmental costs in avoided cost rates, so long as those costs are not speculative. As this report shows, several states already account for avoided environmental costs in the review of energy efficiency programs. FERC should review those provisions and suggest methodologies that states could adopt for use in setting avoided cost rates.

However, few states are adopting either resource- specific QF rates or QF rates that reflect avoided environmental costs. State utility regulators may not be aware that PURPA authorizes these approaches, or they may be unsure of what methods they should use to implement such policies. FERC analysis of these issues, by considering regional variation in conditions such as resource sufficiency and deficiency, could facilitate thoughtful policy deliberation by state utility regulators and enhance the deployment of clean and efficient energy resources.

In light of these issues, FERC's leadership is needed to ensure the continued vitality of PURPA and its goal of encouraging development of small, alternative power technologies, including renewable energy and cogeneration. FERC's leadership is also needed to bring some clarity to the use of avoided costs as a metric for measuring the system benefits of energy efficiency. To this end, FERC should use its decision in *California Utilities Commission* as a starting point to reaffirm states' ability to set resource-specific QF rates and consider other factors such as avoided environmental costs.

FERC could pursue these issues either by convening a series of regional technical conferences, or by issuing a Notice of Inquiry to gather data and other input on existing avoided cost methodologies from stakeholders in order to develop a detailed understating of how PURPA is implemented at the state level and whether the factors articulated in FERC's decision are being taken into account. FERC could also seek comment on whether the program evaluation and ratemaking practices used in energy efficiency programs appropriately use avoided cost forecasts.

Although Congress afforded utilities opportunities to seek relief from their PURPA obligations, significantly, Congress did not abolish PURPA entirely. PURPA remains a valid law, yet its original purpose of encouraging alternative power development remains unfulfilled. Furthermore, the use of avoided costs in the context of energy efficiency program analysis and ratemaking is an unanticipated extension of PURPA's intent. By taking the actions recommended in this paper, FERC can administer PURPA in an efficient and logical way that results in just and reasonable rates which are nonetheless sufficient to encourage renewables, CHP and small power production so that developers and ratepayers can enjoy its benefits.

APPENDIX
DISCUSSION OF STATE CHOICE OF AVOIDED COST METHODOLOGIES

Appendix Contents

APPENDIX: DISCUSSION OF STATE CHOICE OF AVOIDED COST METHODOLOGIES

These nine states' approaches were selected after reviewing a larger pool of jurisdictional approaches to represent the different methods described above.

1. Massachusetts

In Massachusetts, markets are regarded as competitive and as such, QFs are not viewed as requiring special treatment. Thus, regulated as-available or standard offer contracts are not available to QFs in Massachusetts. Avoided cost measurement is tied to the hourly market clearing price for energy and the monthly clearing price for capacity, as measured by the NE ISO. Mass Regs Code tit. 220, s. 8.05.

2. California

California has several approaches for setting avoided cost. California recognizes that QFs are now better able to compete in more competitive markets and also that overly generous QF standard contracts left ratepayers with higher rates. The variety of rates offered by California, particularly to smaller QFs of under 20 MW, reflects a desire to continue to support QFs but strike an appropriate balance between ratepayer impacts and QF developments.[93]

California offers a combination of market rates (for short-run contracts). The Commission determined that firm power and as-available power cannot be priced identically since firm unit contingency capacity is more valuable to purchasers.

California uses the proxy unit method (fixed payments based on the cost of a CT unit) for as-available capacity. For long-term capacity costs, California

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[93] See *Decision 07-09-040, Opinion on Future Policy and Pricing for QFs* California's 2007 opinion on avoided cost ratemaking, which is still largely current, discussed the possibility of the termination of the mandatory purchase provision in PURPA. However, because utilities still remained subject to PURPA mandatory purchase obligation at the time the 2007 decision issued, California did not change any of the provisions. However, in March 2011, the utilities filed a request, as part of a proposed CHP settlement, to terminate the mandatory purchase obligation – and doing so, might lead to changes to avoided cost rates.

uses a market referent price (MPR) based on a CCGT unit cost. (California Dec. Slip Op at 102).

- **The Market Index Formula (MIF)** is an updated SRAC formula for pricing SRAC energy. The MIF is based on the Decision (D.) 01-03-067 Modified Transition Formula but contains both a market-based heat rate component and an administratively determined heat rate component to calculate the incremental energy rate (IER);

- **Standard Contract Options for Expiring or Expired QF Contracts and New QFs**:
    - One- to Five-Year As-Available Power Contract.
    - One- to Ten-Year Firm, Unit-Contingent Power Contract.
    - QFs will also continue to have the option of either participating in Investor-Owned Utilities (IOU) power solicitations or negotiating bilateral contracts with the IOUs.

- **Prospective QF Program Contract Provisions**
    - Short-Term (1-5 years) As-Available Contracts:
        - SRAC Energy Payments: MIF. Existing QF contracts providing SRAC energy will also be priced pursuant to the MIF.
        - Payments for As-Available Capacity: Based on the fixed cost of a CT as proposed by The Utility Reform Network (TURN), less the estimated value of Ancillary Services (A/S) as proposed by San Diego Gas & Electric Company (SDG&E) and capacity value that is recovered in market energy prices as proposed by TURN and SDG&E.
    - Longer-Term (1-10 Years) Firm, Unit Contingent Contracts:
        - Energy Payments: MIF.
        - Capacity Payment for Firm: Based on the market price referent (MPR) capacity cost adopted in Resolution E-4049, less the value of energy-related capital costs (or inframarginal rents) as proposed by SCE.

3. Idaho

Idaho uses a proxy unit method for avoided capacity costs for standard contracts. Previously, QF units up to 10 MW were eligible for these contracts; however, due to expansive growth of Idaho's wind program, only wind and solar projects of 100 kW or less are eligible for standard offer contracts. Idaho employs a SAR, a hypothetical resource, as its proxy unit. The SAR is a gas-fired CCCT unit, which the Idaho commission considers to be representative of a plant that a utility is likely to build. Previously, a hypothetical coal-fired steam plant with state-of-the-art emission controls served as the basis of the SAR.[94] The SAR method also includes generic values for capital costs and fixed and variable O&M.

Idaho has two energy rates for standard offer contracts: one for fossil fueled projects, and the other for "non-fueled" projects which include hydro, wind, solar, and biomass. The rates for fueled projects are adjustable and intended to track natural gas prices.[95] Idaho uses a price forecast for gas which includes the NPCC nominal fuel price escalation rate. Non-fueled projects have fixed rates, which are generally higher than rates for fueled projects.[96]

For projects that exceed the size limit for the standard contract, Idaho uses an IRP-based DRR approach.[97] First, the utility determines through its least-cost plan model the cost of meeting load over the next 20 years. Whenever a proposed QF project is offered to the utility, the utility inserts the generation and capacity of the project into the model and determines what cost would be avoided over the 20-year period. That avoided cost is the rate available to the developer. The

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[94] 1995 Ida. PUC LEXIS 126.

[95] Fueled and non-fueled is a term-of-art distinction in Idaho. Non-fueled projects are renewables projects while fueled projects use non-renewable fuel sources.

[96] *In the Matter of Petition of Idaho Power Company for a Declaratory Order Concerning Entitlement to Published Rates for Non-fueled Small Power production Facilities*, Order No. 28945 (2002)(explaining difference between fueled and non-fueled projects).

[97] Recently, Idaho determined that wind and solar projects larger than 100 kw would no longer be eligible for standard contacts in light of utility concerns that they could no longer accommodate additional wind power. Previously projects of up to 10 MW were able to qualify. Idaho Commission, Docket GNR-E-10-04.

Idaho Commission explains that requiring developers of such projects to prove their viability by market standards ensures that utilities will not be required to acquire resources priced higher than would result from a least-cost planning process.[98]

4. Utah

Like Oregon, Utah applies different methodologies depending upon whether utilities are in a resource sufficiency or deficiency period.[99] During periods of resource sufficiency (as determined by a utility's IRP) avoided costs are determined using the DRR method. This is done by evaluating system energy costs with and without the addition of a 10-MW, zero-cost resource. Capacity payments are based on the fixed costs of a SCCT proxy resource for months during the resource sufficiency period in which the utility is capacity deficient and the utility plans to purchase this capacity.

During periods of resource deficiency, avoided capacity and energy costs are based on the proxy plant method. Avoided capacity and energy costs are developed from the expected costs of resource(s) the utility plans to build or buy and which are avoidable or deferrable.[100]

5. Montana

Montana's standard rates apply to QFs up to 10 MW. For NWE (the primary utility), there are several rate options for non-wind and three rate options for wind. The Montana Commission adopted a multi-option approach to expose ratepayers and QFs to different risks and opportunities and extend non-discriminatory opportunities to QFs. The various standard offer rates are calculated as follows:[101]

Option 1 is based on a projection of the revenue requirements for the Colstrip-4 coal-fired plant as a proxy on a levelized basis. The costs are separated into energy and capacity by using the 2007 RPP/FSCCCT costs as the

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[98] Idaho, 2009 Ida. PUC LEXIS 161.

[99] Docket No. 09-035, 2009 Utah PUC LEXIS 420 (2009).

[100] *Id.*

[101] *IN THE MATTER OF the Northwestern Energy's Application for Approval of Avoided Cost Tariff For New Qualifying Facilities* (2010 Mont. PUC LEXIS 31).

basis for capacity costs. Option 1 applies to long-term, short-term and wind-only contracts.

Option 2 offers two market-based rates based on the market-based acquisition price for Colstrip 4 – which is a proxy for the cost of baseload market products that NWE will avoid with its purchase of QF power.

QFs larger than 10 MW must compete and can receive a long-term contract through an all source competitive bid selection. Pending selection in a competitive solicitation, all QFs are entitled to sell power under a short-term avoided cost tariff or short-term contract.

Option 3 establishes a standard rate for wind that reflects costs NWE would incur to acquire alternate wind resources. The Commission noted that a wind-only rate was necessary given that 85 percent of QFs in NWE's queue are wind.

6. Oregon

In Oregon, the Commission has emphasized policies such as the need for avoided costs to accurately reflect incremental costs and avoiding burdens to ratepayers.[102] Thus, Oregon requires different methodologies in resource sufficient and deficient periods (as determined by the IRP).

For resource deficient periods, Oregon uses the proxy method. Avoided cost rates reflect the variable and fixed costs of a CCCT.[103] The Oregon Commission rejected use of a market methodology in resource deficient periods and chose the proxy methodology instead because it better reflected the longer-term resource decisions that a utility must acquire when it is in a deficient period. The Commission explains:

> Although a utility may acquire market resources as demand gradually builds, at some point the increase in demand warrants the utility making plans to build or acquire long-term generation resources. At that point, calculation of avoided costs should reflect the potential deferral or avoidance of such generation resources.[104]

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[102] Order 05-584.

[103] Oregon is currently considering an alternative approach which would base avoided cost rates on either CCCT as a proxy unit or the next renewable resources as a proxy. 2010 Ore. PUC LEXIS 423.

[104] 242 P.U.R.4th 140 at *78.

The Oregon Commission also offers several options for setting prices once the proxy methodology is adopted. Consistent with its desire for accuracy, the Oregon Commission offers three pricing methodologies: (a) fixed pricing, which sets prices at the time the contract is executed and is based on forecasted natural gas pricing; (b) deadband method, which binds a QF's rates within a floor and ceiling based on 90 to 100 percent of the natural gas price forecast in the avoided cost filing; and (c) the gas market method, which uses a monthly indexed price with no forecast to set avoided cost rates.[105] The Oregon Commission also believes that these different options will afford flexibility to QFs to choose avoided cost payments that will best support the project.

When a utility is in a resource sufficient position, the Commission determined that avoided cost would be valued based on an energy-only option reflecting monthly on- and off-peak, forward market prices as of the avoided cost filing.

7. North Carolina

In North Carolina, utilities submit biennial avoided cost calculations and the North Carolina Commission approves a variety of approaches. North Carolina has approved use of both the DRR and peaker approach, finding that these methodologies are generally accepted throughout the electric industry – and that the three utilities in the state (Progress Energy Carolinas, Duke Energy Carolinas, and Dominion North Carolina Power) should not be required to use a common methodology.[106] Standard rates must be offered based on one of these approaches: for example, Progress Energy provides standard contracts of 5, 10 and 15-year duration with levelized capacity and energy rates calculated by the DRR methodology for hydro QF and waste, solar, wind or biomass QFs of 5 MW or less. Standard contracts are available for hydro QFs of 3 MW or less. North Carolina makes longer-term standard contracts available to encourage these technologies. As an alternative to DRR, these QFs may choose avoided cost rates based upon the Locational Marginal Pricing (LMP) methodology as applied to the PJM Interconnection, LLC (PJM) market.

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105 *Id.*

106 2007 NC PUC LEXIS 1786 at *26.

QFs that do not qualify for standard contracts may participate in a utility's competitive bidding process and receive rates based on selection. When a request for proposals (RFP) is not available, the QF can sell energy at a variable energy rate or at negotiated rates.

8. Georgia

Georgia uses a competitive bidding process to determine the cost of a proxy unit. The utility will determine its needs for long-term capacity and use the RFP process to set avoided cost payments. Georgia uses this approach to protect ratepayers and ensure that they do not overpay.[107]

QFs of 5 MW or more must bid into the RFP; QFs of 5 MWs or less are exempt and may accept the avoided cost of the first displaced bidder without participating. By using the prices received through the bid process, a proxy base load unit can be created that reflects the same overall cost as the bid price would create over time.[108] Capacity costs reflect units identified in RFP.

9. Florida

Florida uses a proxy methodology. Rules 25-17.250(1) and (2)(a), of Florida's Administrative Code, require each electric IOU to annually file a standard offer contract for the purchase of firm capacity and energy from renewable generating facilities and small qualifying facilities with a design capacity of 100 kW or less. The standard offer contracts reflect each IOU's next avoided unit shown in its most recent Ten-Year Site Plan.

The utility may close its standard offer when one of the following events occurs. First, once the utility issues an RFP for an avoided unit, it can close the standard offer. But, the utility can also close the standard offer in the absence of, or prior to the issuance of, an RFP. For instance, when the utility identifies the avoided unit that is the basis for a standard offer, it will propose a limit as to the amount of QF capacity that will "fully subscribe" the avoided unit. Once the limit has been reached, the utility can act to close the standard offer (and propose another based on the next unit in its plan). The utility can request closure of the standard offer at any point at which the avoided unit on which the standard offer contract is based is no longer part of its expansion plan. This may or may not be at the time the utility submits its next Ten- Year Site Plan.

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[107] *Petition of Biomass Gas & Electric*, 2004 GA PUC LEXIS 43 (2005).

[108] *Id.*

The standard offer includes the value of deferred capacity payments (i.e., benefit to utility of deferring, if not entirely avoiding, new capacity).[109] Florida's regulations offer instructions for calculation of standard offer rates for energy and capacity.[110] There are several options. Value of deferral capacity payments consist of monthly payments, escalating annually, of the avoided capital and fixed operation and maintenance expense associated with the avoided unit. They are set the value of a year-by-year deferral of the avoided unit. Levelized capacity payments may also be elected.

Avoided energy cost payments are also made pursuant to rule. To the extent that the avoided unit would have been operated, had that unit been installed, avoided energy costs associated with firm energy are the energy costs of the unit. To the extent that the avoided unit would not have been operated, the avoided energy costs are the as-available avoided energy cost of the purchasing utility. During the periods that the avoided unit would not have been operated, firm energy purchased from qualifying facilities is treated as as-available energy.

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[109] 2008 Fla. PUC LEXIS 620.

[110] Florida Administrative Code 25-17.0732.

Credits

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	CASE NO. 2020-00349

AFFIDAVIT OF JUSTIN BARNES
VERIFICATION

JURISDICTION)
)
County of Wise, Virginia)

The undersigned, Justin Barnes, being first duly sworn, states the following: The prepared pre-filed Direct Testimony, and Exhibits attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the pre-filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further, Affiant saith not.

Name of Witness

SUBSCRIBED AND SWORN to before me on this 4th day of March 2021.

Commonwealth of VA
County of Wise

NOTARY PUBLIC

SABRINA STEWART MULLINS NOTARY PUBLIC REG. #7106596 MY COMMISSION EXPIRES 5/31/2023 COMMONWEALTH OF VIRGINIA

My Commission Expires: 5/31/2023