Unlocking DG Value

A PURPA-based approach to promoting DG growth

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UNLOCKING DG VALUE: A PURPA-BASED APPROACH TO PROMOTING DG GROWTH

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I. Executive Summary

Due to the rapidly growing appetite for solar and other forms of renewable and alternative energy in the U.S., developers, utilities and state energy regulators are seeking policy options that appropriately value the locational benefits of distributed generation (DG). The federal Public Utilities Policy Regulatory Act (PURPA) may provide a solution that supports greater DG development close to load, where DG value is highest. This paper explores the benefits that could be quantified and incorporated into the development of PURPA-based avoided cost rates to more accurately value the energy contribution of distributed facilities that serve local load.

A comprehensive PURPA-based approach to DG policy design would incorporate many as-yet-unquantified benefits of exports to the distribution system, including: line-loss avoidance; the ability to make smaller capacity additions that more closely follow incremental load changes; the deferral or avoidance of utility capital expenditures; and the environmental benefits of displacing fossil-based resources. This paper addresses the advantages and disadvantages of such an approach.

II. Introduction

Distributed generation is a term that lacks a single, accepted definition. In this paper, we consider DG to be a localized form of small-scale electric generation with output that primarily serves local load or is used to directly serve onsite load. DG provides many quantifiable benefits, not only to a potential host of a DG system and user of its output, but also to utilities, ratepayers and the electricity grid. The extent of these benefits, however, often depends on the placement of the DG on the grid, the supply characteristics of the generation and the amount of additional DG on the same line, among other factors.

The DG market, in particular solar photovoltaic (PV) generation has experienced tremendous growth in the United States over the past decade, the majority of which has been facilitated by state net metering programs. At this writing, 43 states plus the District of Columbia, Puerto Rico and the Virgin Islands had adopted net metering policies, and through 2011, ninety-three percent of the grid-connected solar installations in the U.S. were net metered, accounting for more than 3,000 MW-dc of new generating capacity.[2]

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1 The authors wish to thank the following individuals who reviewed this paper and provided feedback: Sarah Bertram, Adam Browning, Susannah Churchill, Rick Gilliam, Eran Mahrer, Bryan Miller, Karl Rabago, Matt Vespa and Ryan Wiser.

2 Larry Sherwood, IREC, *Solar Market Trends: 2011*, Figs. 2 & 6 (Aug. 2012), in addition to unpublished 2012 data, *available at* http://www.irecusa.org/2012/08/irec-releases-its-solar-market-trends-report-for-2011.

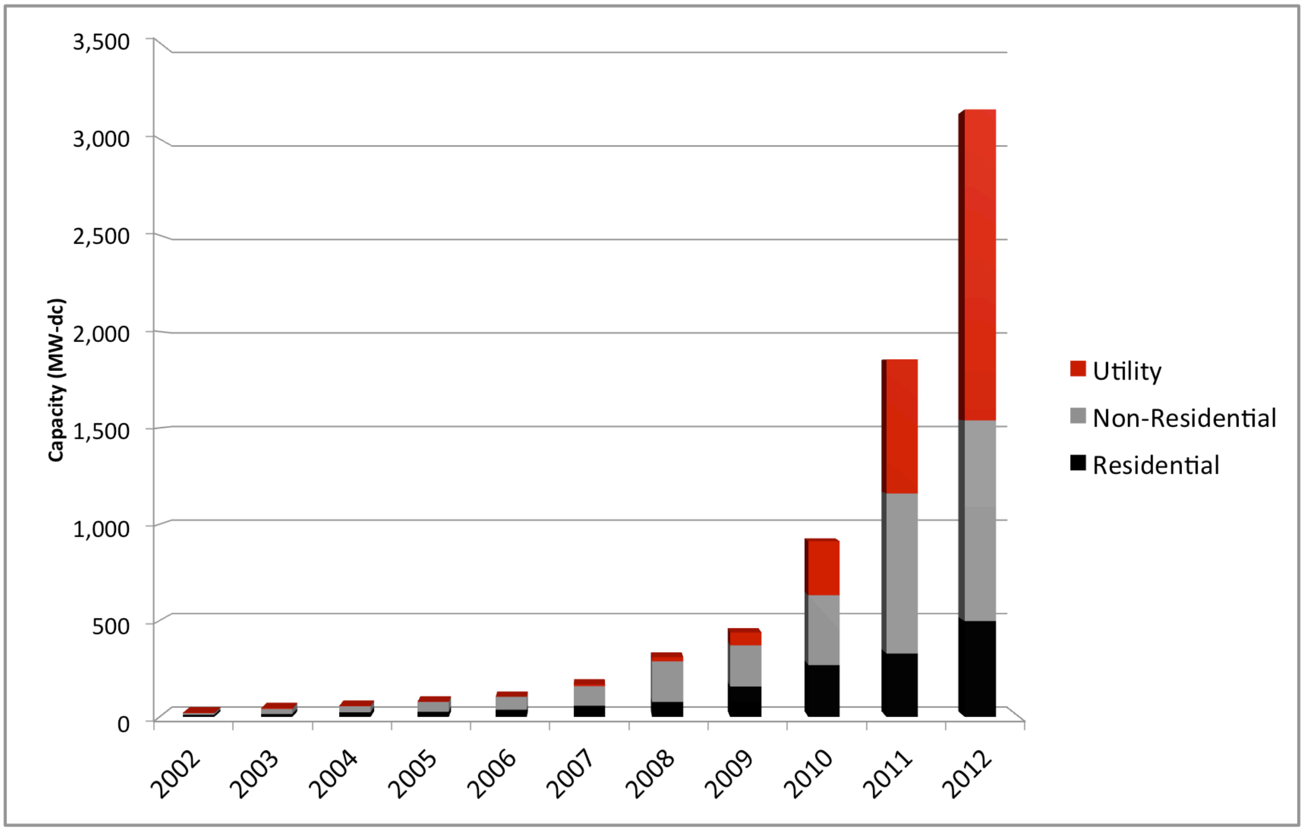

Figure 1: Annual Installed Grid-Connected PV Capacity (MW) by Sector (2002-2012). In the graph above, the residential and non-residential capacity has generally been installed under state net metering programs.

Although net metering policies have proven very successful at facilitating PV growth, they primarily limit generators to serving onsite load and therefore do not facilitate growth in the full range of locations where DG may provide benefits to all utility consumers. This has led to consideration as to whether a PURPA-based approach to facilitating DG growth would be adequate to drive investment in high-value DG, particularly DG that may serve local load, but may not necessarily serve onsite load.

PURPA requires large utilities to purchase available energy and capacity from Qualifying Facilities (QFs) at the utility's avoided cost of producing the next incremental unit of electricity.[3] PURPA emerged as a national policy framework to support the development of diversified and decentralized energy resources in order to reduce reliance on fossil fuels.[4]

In practice, avoided cost rates have typically been set at a level that reflects the cost of generation from large conventional fuel resources and have not been sufficient to support smaller-scale renewable generation, such as PV installations.[5] Nevertheless, PURPA gives states and non-regulated utilities

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3 16 U.S.C. § 824a-3; *see generally* 16 U.S.C. § 2601 *et seq.*

4 *See American Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 405 (1983) (noting that Congress believed requiring purchases from qualifying cogeneration and small power production facilities would reduce demand for traditional fossil fuels).

5 Elefant, Carolyn, *Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Renewable Energy Development and a Proposed Path for Reform*, pp. 2-3.

flexibility in determining standard rates for purchases from QFs, and recent FERC decisions, which are discussed below, have clarified that differentiated QF rates may be adopted that recognize quantifiable benefits of DG. Accordingly, it appears that PURPA may be able to compensate distributed QFs for the value of discrete, quantifiable grid benefits that derive from a combination of location and supply characteristics.

This white paper explores whether a PURPA-based valuation method for PV and other forms of renewable DG may provide a solution that supports greater DG development close to load, where DG value is highest. In the course of this discussion, we identify at least five issues that would need to be addressed before PURPA could be a viable option for promoting DG growth. These include: 1) ensuring that all DG benefits are appropriately valued in setting a distributed QF rate; 2) increasing the eligibility for a standard QF rate above 100 kW; 3) ensuring the ability for distributed QFs to serve onsite load; 4) prohibiting punitive fees and charges from being imposed on customers that use a QF to serve onsite load; and 5) limiting utility options to curtail purchases from distributed QFs.

III. Policy Design Issues

In the past several years, FERC issued several decisions in response to a California effort to establish a feed-in tariff (FIT) program for high-efficiency combined heat and power (CHP) projects. These decisions suggest that FERC's view of the range of values that states may consider in determining avoided cost rates is broadening. Pursuant to its implementation of the CHP FIT program, the California Public Utilities Commission (CPUC) developed a price that would be available only for a limited amount of eligible, high-efficiency CHP projects. In addition to the standard FIT price, the CPUC proposed a 10% price "adder" for projects located in transmission-constrained areas.

In seeking declaratory rulings, California wrestled with FERC precedent, which had held that a PURPA avoided cost rate must consider all resources available to the utility.[6] Despite this precedent, FERC issued an initial order stating that the CPUC's implementation would comply with PURPA so long as the participating CHPs were QFs and that the rate for purchases did not exceed the avoided cost of the purchasing utility.[7] FERC then affirmed that the CPUC was within its authority to develop resource-specific pricing so long as there is a state-mandated requirement to purchase that type of resource.[8] Additionally, FERC clarified that transmission and distribution (T&D) benefits can be included in an avoided cost rate where those benefits are based on actual determination of "the expected costs of upgrades" that the QFs will "permit the purchasing utility to avoid…."[9]

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6 *See So. Cal. Edison*, 70 FERC ¶ 61,215 at 61, 677, *reconsideration denied*, 71 FERC ¶ 61,269 (1995) (holding that a market price derived from an auction must result from all-source bidding and cannot be limited to specific types of QFs).

7 *California Public Utilities Commission*, 132 FERC ¶ 61,047 (July 15, 2010).

8 *California Public Utilities Commission*, Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 at PP 26, 31 (2010).

9 *Id.* (distinguishing the 1995 *So. Cal. Edison* case to clarify that non-renewable resources are not "available" sources of generation where there is a mandate to procure renewable generation).

The most obvious and immediate implication of these FERC decisions is that states may now base avoided cost rates on the costs of specific types of generation being avoided, such as renewable resources, so long as the state has required the utility to buy energy and capacity from that type of resource.[10] This clarification opens the door for a large number of states with renewable generation procurement mandates to establish avoided cost pricing tailored to the specific type of generation segment mandated by state law.[11]

A second aspect of these decisions—the permissibility of including T&D benefits—could prove significant in regard to the ability of states to value DG. As FERC observed, "if the CPUC bases the avoided cost 'adder' or 'bonus' on an actual determination of the expected costs of upgrades to the distribution or transmission system that the QF will permit the purchasing utility to avoid, such an 'adder' or 'bonus' would constitute an actual avoided cost determination and would be consistent with PURPA and our regulations."[12]

In this regard, FERC clarified that other types of benefits that have not traditionally been considered, including location-based benefits, may be included in avoided costs, so long as the QF resources permit the utility to avoid actual costs.[13] Significantly, this aspect of determining avoided cost is not tethered to the existence of a state procurement mandate; it is a reflection of the value of DG. Through this lens, PURPA provides an opportunity to take a location-specific approach to determining avoided costs.

To date, states have not moved in a meaningful way to take advantage of the opportunity FERC's *CPUC* decisions present. However, there is now significant potential to modernize the application of PURPA to develop a comprehensive valuation methodology that will attract renewable generation into QF programs and spur growth in DG markets. Below, we discuss the benefits that should be quantified and incorporated into an avoided cost payment for DG exports. We also discuss the importance of allowing a DG customer to use onsite generation to self-supply electricity needs.

1. Exports To The Distribution System

FERC's regulations allow states and non-regulated utilities to consider numerous factors in determining avoided costs, all of which should be considered in setting QF rates for exports to electric utility distribution systems. These include:

- Reduced line losses;[14]
- Ability to install smaller increments of capacity with shorter lead times;[15]
- Ability to avoid or defer T&D costs;[16]

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10 *California Public Utilities Commission*, Order Denying Rehearing, 134 FERC 61,044 (2011).

11 See generally J. Gleason, Adopting State Feed-in Tariff Laws without Federal Preemption, Environmental Law Alliance Worldwide, http://www.elaw.org/node/5741http://www.elaw.org/node/5741.

12 *California Public Utilities Commission*, Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 at P 31 (2010).

13 *Id. California Public Utilities Commission*, Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 at P 31 (2010) (CPUC II). *Id.*

14 18 C.F.R. § 292.304(e) (4).

15 18 C.F.R. § 292.304(e) (2)(vii).

- Value of QF capacity and energy;[17]
- Ability to dispatch QF output;[18] the expected or demonstrated reliability of the output;[19] and the usefulness of QF production during system emergencies;[20]
- Environmental benefits and renewable attributes of QF power;[21] *and*
- Duration and enforceability of QF contract.[22]

The following sections discuss these factors, which should be taken into account in setting DG-specific avoided cost rates for QFs interconnecting to electric utility distribution systems (referred to below as "distributed QFs"). In several cases, alternative approaches are discussed.

a) Reduced Line Losses

Distributed QFs can be located close to load centers, thereby reducing line losses that occur from transporting electricity over long distances from more remote generators. This represents a quantifiable savings to utilities that should be incorporated into rates for distributed QFs.[23] FERC's regulations expressly provide for that outcome.[24] QF generation that is locally consumed allows the utility to avoid producing the additional unit of electricity it would need from more distant generators to account for line losses during delivery to the ultimate consumer. Line loss values differ by utility and time of year, but they are generally in the range of 7-11% for California utilities, and may be in the a similar range for other utilities.[25] Utilities typically disclose line loss values as a loss factor, which is used to estimate how much additional generation is required to meet load.[26]

b) Ability to Install Smaller Increments of Capacity with Shorter Lead Times

Distributed QFs can often be installed with short lead times. In particular, QFs interconnecting to low-voltage distribution systems (generally up to 23 kV or 34 kV) with existing capacity can generally be interconnected more quickly and inexpensively than larger QFs and non-QF generators that interconnect

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16 18 C.F.R. § 292.304(e) (3).

17 18 C.F.R. § 292.304(e) (2)(vi).

18 18 C.F.R. § 292.304(e) (2)(i).

19 18 C.F.R. § 292.304(e) (2)(ii).

20 18 C.F.R. § 292.304(e) (2)(v).

21 *See, e.g., California Public Utilities Commission*, Order Granting Clarification, 133 FERC 61,059 at P 31 ("[I]f the environmental costs 'are real costs that would be incurred by utilities,' then they 'may be accounted for in a determination of avoided cost rates.'"). (quoting *So. Cal. Edison*, 71 FERC ¶ 61,269 at 62, 080).

22 18 C.F.R. § 292.304(e) (2)(iii).

23 *See* FERC Order No. 69, 45 Fed. Reg. 12214 at 12227 ("If the load served by the [QF] is closer to the [QF] than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.")

24 18 C.F.R. § 292.304(e)(4).

25 Lana Wong, *A Review of Transmission Losses in Planning Studies* (California Energy Commission), at 2, CEC-200-2011-009 (August 2011).

26 *Id.* at 11.

to medium-voltage sub-transmission systems (generally above 23 kV or 34 kV up to 69 kV) and high-voltage transmission systems (generally 69 kV and above).[27]

Economies of scale drive central generating plants to be fairly large, but larger generators may represent more capacity than is immediately needed to meet utility load service and reserve requirements. Significant additions in capacity are often classified as "lumpy" and may not be well suited to matching more incremental changes in load. There may be a quantifiable benefit to utilities from meeting incremental changes in load with smaller, distributed QFs that can be located closer to where load growth is occurring. According to FERC:

> Such reduced lead time might produce savings in the utility's total power production costs, by permitting utilities to avoid the "lumpiness," and temporary excess capacity associated therewith, which normally occur when utilities bring online large generating units. In addition, reduced lead-time provides the utility with greater flexibility with which it can accommodate changes in forecasts of peak demand.[28]

In sum, distributed QFs may be capable of being deployed to meet incremental needs and that benefit should be quantified and incorporated in avoided cost rates for distributed QFs.

c) *Ability to Avoid or Defer T&D Costs*

Locating QF capacity on the distribution system may help reduce transmission congestion and the need for T&D resources, particularly for QFs that serve onsite or nearby load.[29] This benefit is driven by a QF's ability to reduce loading on local distribution system infrastructure, leading to potential delay or avoidance of T&D investments.

A utility's ability to defer T&D investments depends on whether there are planned T&D upgrades that local QF capacity may help avoid, among other factors. The extent to which T&D costs may be avoided also depends on the alignment of DG production with demand characteristics on the utility system and the ability for the DG capacity to be relied upon to serve load during peak events.[30] Utilities plan T&D capacity to meet peak load conditions. If local QF capacity is not aligned with and reliable during peak demand on the utility system, avoided T&D benefits may be limited.[31]

Integrating a limited amount of storage onto the distribution system could provide for better alignment of generation and peak load and offer an alternative to adding T&D capacity.[32] Additionally, such storage (and even "smart" DC/AC inverters) can provide needed short-term ancillary services such as frequency response, voltage control, and reactive power. To the extent storage provides benefits to

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27 See presentation slide #45 from Adam Schultz, from a CPUC Renewable DG Technical Potential Workshop, available at https://www.pge.com/regulation/RenewablePortfolioStdsOIR-IV/CPUC-Docs/CPUC/2013/RenewablePortfolioStdsOIR-IV_Doc_CPUC_20130129_261440Atch02_261615.pdf.

28 FERC Order No. 69, 45 Fed. Reg. 12214 at 12227.

29 *Id.* at P 31.

30 *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System* (SCE) at p. 9 (May 2012).

31 *Id*.

32 *Id*. at 62.

utility ratepayers, policymakers will need to determine how to allocate storage costs between ratepayers and distributed QFs.

Higher penetrations of DG may lead to distribution costs in the form of additional capital expenditures, however, under federal and most state interconnection processes, distributed QFs would pay the cost of distribution system upgrades necessary to interconnect a generating facility safely and reliably.[33] Accordingly, distributed QFs would typically pay additional capital expenditures that are necessary to accommodate the new generation, including increased T&D costs at higher penetrations. Although these upgrades may benefit utility ratepayers, such benefits seldom result in compensation to a distributed QF.

Developing location-specific avoided cost pricing to compensate distributed QFs for T&D benefits may be difficult to develop with a high degree of precision. The types of granular information at the distribution circuit level that would be necessary to determine the types of utility investments that could be avoided by adding a targeted amount of QF capacity are often not fully disclosed. A more generalized approach for compensating QFs for avoided T&D benefits may be necessary.

One approach would be to develop "rules of thumb" to estimate an average value for avoided T&D to which individual QFs contribute. This is similar to the approach discussed below for determining an aggregate capacity value. For example, a higher avoided cost payment could be provided to any QF that is able to serve nearby load without requiring extensive T&D facilities.

Standard interconnection processes established by FERC and at the state level often include screening approaches that could be helpful in determining whether proposed QF capacity will serve local load.[34] Using such an eligibility criterion, state regulators and non-regulated utilities could develop an aggregate system-wide T&D value for QFs that satisfy the criterion.

Distributed QFs that primarily serve local load on the same distribution circuit to which the QF is interconnected should not require the use of the upstream transmission system to carry power to customer load. The avoided need for transmission infrastructure represents a quantifiable avoided cost to a utility in meeting its load service obligations and would appear to have a strong argument for being reflected in avoided cost pricing for QFs that interconnect to the distribution system and primarily serve local load.

Another approach, which could be combined with the above approach, may be to identify high-value areas of need on the distribution system where the addition of QF capacity may help avoid or delay T&D investment. Discrete, location-specific values could be developed for these areas that reflect the specific costs that will be avoided by QFs locating in those areas. Compensating QFs for locating in

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33 California is a notable exception in which net metered customers and certain solar facilities do not pay the cost of distribution system upgrades.

34 For example, the FERC's Small Generator Interconnection Procedures (SGIP) feature a technical review screen, which is also utilized in many states, that limits the aggregate generation on a circuit to 15% of the line section annual peak load as most recently measured at the substation. SGIP § 2.2.1.2. FERC is also considering modifications to SGIP that would introduce a supplemental review screen set at 100% of minimum load on the line section.

such areas would provide an appropriate price signal for distributed QFs to locate in areas where known T&D benefits would materialize.

Once distributed QF capacity reaches a level where additional QF capacity will no longer serve local load or produce know T&D benefits, QFs still have a general right under PURPA to interconnect and sell to the utility. Because QFs may not enable the utility to avoid additional T&D costs in such areas, additional capacity may no longer be eligible for compensation that reflects avoided T&D benefits. In this way, a properly designed standard rate should be capable of incentivizing location-specific development that maximizes the use of the existing distribution system and sends price signals to locate in other areas as T&D benefits are exhausted.

d) Value of QF Generating Capacity and Energy

Since many QF technologies, such as solar and wind, have generating characteristics that are variable, it may be difficult to assign a capacity value to individual generators. FERC's regulations, however, require a consideration of "the individual *and aggregate* value of energy and capacity from qualifying facilities on the utility's electric system…."[35] In FERC Order 69, FERC directly contemplated the possibility that variable generation resource should be assigned an aggregate capacity value due to geographic or technological diversity. According to FERC:

> In some instances, the small amounts of capacity provided from [QFs] taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual [QF] may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.[36]
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> [F]or example, wind machines that furnish power only when wind velocity exceeds twelve miles per hour may be so uncertain in availability of output that they would only permit a utility to avoid generating an equivalent amount of energy. In that situation, the utility must continue to provide capacity that is available to meet the needs of its customers. Since there are no avoided capacity costs, rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy. On the other hand, testimony at the Commission's public hearings indicated that effective amounts of firm capacity exist for dispersed wind systems, even though each machine, considered separately, could not provide capacity value. The aggregate capacity value of such facilities *must* be considered in the calculations of rates for purchases, and the payment distributed to the *class* providing the capacity.[37]

It is important to note that the aggregate capacity value for distributed QFs may vary by technology and depend on the geographic location of the utility and other factors. A recent report from the Lawrence Berkeley National Laboratory found that utilities varied widely in their current practices to incorporate factors like capacity value, energy value, and integration costs of solar.[38]

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35 18 C.F.R. § 292.304(e)(2)(vi) (emphasis added).

36 FERC Order No. 69, 45 Fed. Reg. 12214 at 12227.

37 FERC Order No. 69, 45 Fed. Reg. 12214 at 12225 (emphasis added).

38 *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes*, available at: http://emp.lbl.gov/sites/all/files/lbnl-5933e_0.pdf.

In establishing energy values for classes of QF generators, PURPA allows QF output to be valued based on the time at which electricity is delivered to the grid. In fact, many of the criteria developed by FERC to inform avoided cost determinations relate to the ability of QFs to provide energy and capacity during peak-periods.[39]

Technologies like solar photovoltaics generally provide energy and capacity during daytime hours, when the costs of alternative energy to the utility are typically highest. Solar photovoltaic output correlates particularly well with high load conditions at summer-peaking utilities. Other QF technologies may also provide similar peak-supply benefits. These peak-period values should be considered in setting capacity values for classes of QF generators.

The capacity and energy value for QFs can be limited by whether a given utility has capacity needs in the near future, and higher penetrations may lead to lower marginal capacity and energy value, and therefore declining avoided costs. Utilities vary in their perspective of the planning horizon. For example, if a utility will need a 300 MW plant eight years in the future, the incremental capacity value of QFs may not be recognized for eight years because additional QF capacity is not deferring an identified need until that far out. To reconcile this discrepancy, states may need to adjust how they traditionally consider and value capacity needs.

e) Ability to Dispatch QF Output; Expected or Demonstrated Reliability of the Output; and Usefulness of QF Production During System Emergencies

Different types of DG naturally present varying characteristics that can affect their value based on the generator's capabilities for dispatchability, reliability and emergency production. These characteristics include factors such as whether the generation is firm and available at scheduled times and at controllable levels (i.e, biomass, geothermal electric, hydropower and many fossil-based resources) and the time-of-day and seasonal characteristics of the generation (i.e solar PV predictably produces energy during peak hours of the day).

Variable resources, such as wind and solar, carry limitations regarding reliability and dispatchability because they are generally available on a non-firm or "as available" basis. These characteristics are typically taken into account in avoided cost rate setting. Variable resources may also impose reliability challenges and integration costs at high penetration, but these costs are not unique to QFs and determinations on how to allocate the cost of integrating high penetrations of variable generation will likely take place outside of avoided cost rate setting.

f) Environmental Benefits and Renewable Attributes

Several mechanisms could be used for compensating certain distributed QFs for the use of a renewable fuel source and the production of resulting environmental benefits. First and foremost, to the extent low or zero-emission QF resources allow a utility to avoid emissions permits and other environmental costs associated with alternative sources of generation, those costs can be included in an avoided cost rate.[40]

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39 *See* 18 C.F.R. § 292.304(e)(2).

40 *See, e.g., California Public Utilities Commission*, Order Granting Clarification, 133 FERC 61,059 at P 31.

In addition, in the case of QFs fueled by renewable resources, an owner of distributed QF generation ordinarily owns the renewable "attributes" associated with that generation. The property right associated with the renewable attributes is often embodied in tradable Renewable Energy Credits or Certificates ("RECs") that may be conveyed for value separate from an avoided cost sale. As a creation of state law, FERC recognizes that "[c]ontracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility (absent express provision in a contract to the contrary)."[41] Thus, avoided cost rates under PURPA do not compensate renewable QF generators for their renewable attributes, as those are embodied in RECS, absent state law or contractual provisions that clearly determine that RECs, or environmental attributes, are conveyed as part of a QF payment.[42] Accordingly, if QF energy and capacity rates are based on avoided conventional fuel resources, additional compensation should be provided for the renewable "attributes" associated with that generation, which can be structured as a price paid for RECs.

Finally, FERC's *CPUC* decisions create a third possibility for compensating renewable QF generators for the renewable attributes of their generation. To the extent states have established a mandate for procuring a specific type of resource (high efficiency CHP in the case of the *CPUC* decisions), utilities subject to that mandate will have an avoided cost specific to procuring that resource or class of resources until the mandate is satisfied. Presently, 29 states plus D.C. have established a renewable portfolio standard ("RPS") that requires utilities subject to the RPS to incorporate targeted amounts of renewable generation into the utility's procurement portfolio.[43] Sixteen of those states plus D.C. have further specified types of renewable generation, e.g. solar, or locations for resources, e.g. DG, that must be met.[44] These procurement requirements have an avoided cost associated with meeting the mandate. FERC's *CPUC* decisions accordingly allow an avoided cost to be identified for each. This represents a third potential mechanism for compensating distributed QFs for the renewable attributes of their generation, in addition to payment for RECs and the incorporation of avoided environmental compliance costs into avoided cost rates.

g) Duration and Enforceability of QF Contract

The QF development process is capital-intensive and often requires long term contracts to attract financing.[45] Therefore, the availability of long-term certainty, in the form of 20-year (or longer) contracts, is often critical to supporting developer and customer investment. On the other hand, developers often need flexibility in determining contract lengths and options to suit the needs of the project and should therefore be provided with several options. Contract length can also determine the duration during which a distributed QF will allow a utility to plan for deferred or avoided any generation and T&D capacity costs. An example of this can be seen in California's former Market Price Referent (MPR), which provided several rate options based on varying contract lengths.[46]

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41 *American Ref-Fuel*, 105 FERC ¶ 61,004 at P 23 (2003), *reh'g denied* 107 FERC ¶ 61,016 (2004).

42 *Morgantown Energy Assoc.*, 139 FERC ¶ 61,066 at P 47 (2012).

43 *Database of State Incentives for Renewables and Efficiency* (DSIRE), available at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

44 Id., available at http://www.dsireusa.org/documents/summarymaps/Solar_DG_RPS_map.pdf.

45 *Reviving PURPA's Purpose*, at P 3.

46 See MPR model, available at http://www.ethree.com/public_projects/cpuc3.php.

2. Electricity Consumed Onsite

Electric utility service is highly regulated to ensure it is accessible at just and reasonable rates without undue discrimination in pricing. At the same time, advances in technology are providing electricity consumers with more options for meeting electricity supply needs than once existed, including the option of self-generation. This is particularly true for generating technologies that use wind, solar, biomass, landfill gas and other renewable resources, which have become increasingly affordable on smaller scales. For consumers to have meaningful options to adopt these technologies, they must be allowed to serve their onsite energy needs without being exposed to discriminatory charges. Consumer adoption can also be facilitated with bill credit mechanisms and netting arrangements that simplify the administrative arrangements between consumers and utilities.

a) Discriminatory Fees and Charges Cannot Be Imposed on Customers that Serve Onsite Load

PURPA requires that QFs have the ability to serve onsite load,[47] and FERC's regulations prohibit the charging of discriminatory retail rates to consumers that use QFs to offset onsite load.[48] Electricity consumers are typically charged for service based on volumetric use (kWh-denominated charges), maximum demand (kW-denominated charges), and on the basis of fixed charges that do not vary with usage (flat-rate charges).

With regard to fixed charges, it is reasonable for self-supply customers to face the same fixed charges (for example a monthly customer charge) as other customers that do not self-supply, unless it can be demonstrated that there are differences in fixed costs of providing service that justify discrimination in pricing. With regard to charges based on maximum demand, customers with variable generation typically see little or no reduction in charges that are based on maximum demand. To the extent customers with variable generation can reduce their maximum demand, particularly during utility peak demand periods, a reduction in charges based on maximum demand may be justified because it results in a reduction in the cost of providing service to these customers.

With regard to charges based on volumetric usage, as with energy efficiency and conservation, customers that self-supply electricity and use it onsite should have the ability to purchase less electricity from a regulated utility without financial penalty imposed by the utility. Accordingly, there is no justification to treat customers with onsite generation differently from those that do not self-supply some of their energy needs unless there are demonstrable differences in the cost of serving these customers that are not offset by commensurate benefits.

b) Export Payment Could be Provided Through a Bill Credit Mechanism

The owner of a distributed QF may or may not have onsite electricity needs to serve with QF generation. To the extent onsite needs exist, and that onsite need is not fully supplied by QF generation, purchases of electricity from a utility will be necessary. That leaves the possibility of sales being transacted in two directions – both from and to the utility.

47 18 C.F.R. §§ 292.303, 292.205(b); *Entergy Services, Inc. v. FERC*, 400 F.3d 5 (D.C. Cir. 2005); *So. Cal. Edison v. FERC*, 443 F.3d 94, 102 (D.C. Cir. 2006); *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 (Oct. 4, 2011).

48 18 C.F.R. § 292.305(a)(1)(ii); *Pacific Gas and Electric Company*, 110 FERC ¶ 63,026 (Feb. 9, 2005).

Net energy metering programs provide a bill credit for exported power using a mechanism that values exports based on a customer's retail rate components. The simplicity of that mechanism has a value that that can also be incorporated into a PURPA-based approach to promoting DG growth. Payment for power received by the utility could be applied as a bill credit to offset the customer's purchase of electricity from the utility, thereby retaining the simplicity of a bill credit mechanism, but without compensation being tethered to retail rate components.

Similarly, payment for distributed QF power could form the basis for compensating participants in a community-shared solar program. A challenging aspect of implementing community-shared solar programs has been gaining agreement on the appropriate approach for valuing exports from a community-shared solar system. Participants in a community-shared solar system could be compensated via a PURPA-based approach, through a bill credit mechanism that applies payment at a PURPA rate to a participant's utility bills.

c) Exports and Imports Could be Netted Against Each Other for Smaller QFs

For small QFs that primarily serve a consumer's onsite electricity needs, the cost of separately metering and valuing exports and utility-supplied electricity may prove more costly than simply netting kWh sold to the utility against kWh purchased from the utility. In such cases, exports and imports could be netted against each other during a typical utility billing period with payment provided by either the utility or the customer (depending on who provides more power to the other). This approach is fully supported by FERC precedent.[49] If the customer provides more power to the utility, the excess energy provided could be valued at the distributed QF avoided cost rate with payment made to the customer.

IV. Potential Advantages

There are a number of potential benefits to a PURPA-based approach for valuing exports.

a) Ability to Determine an Export Rate

Determining an appropriate export rate has been an especially difficult undertaking for community-shared solar programs, feed-in tariffs and other programs in which generating facilities do not serve onsite load and therefore make more extensive use of the electric distribution system. PURPA provides a path to establishing a payment that is equal to the value provided.

b) No Onsite Load Requirement

Net metering programs typically require generators to be sized to serve onsite load, which limits the size of a generator that can be installed to whatever is necessary to serve onsite load. Without community-shared solar or feed-in tariff programs, distributed QFs may be limited to locations where they will primarily serve onsite load. A PURPA-based approach for compensating exports could be provided to generators regardless of location and the degree to which onsite load is being served, meaning available land area or roof space could be fully utilized.

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49 *See, e.g., MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001); *SunEdison LLC*, 129 FERC ¶ 61,146 (2009).

c) Casts a Relatively Wide Net

In addition to most investor-owned utilities, PURPA applies to larger non-regulated utilities, such as municipal utilities and cooperatives, which are often not required to offer net metering or other DG programs. Thus, PURPA has a considerable footprint. Our research indicates that PURPA applies to utilities that cover approximately 85% of the electricity sales in the U.S..

d) Does Not Replace Net Metering

A value-based QF standard rate can provide states and non-regulated utilities a means of appropriately compensating distributed QFs without unsettling parallel policies that promote DG. In the case of net energy metering, for example, customers are generally driven by a variety of reasons to adopt on-site generation, and many customers may decide to install a net-metered generator in an area that would also be eligible for a special, value-based QF standard rate. Ultimately, the customer could decide which policy fits its particular needs.

V. Potential Disadvantages

PURPA carries several disadvantages that would need to be carefully considered in the design and implementation process.

a) Will the Price Level Facilitate Growth?

Absent a technology-specific state procurement mandate, avoided cost rates are inherently technology-indifferent, and as a result are generally set at a level that is equal to the lowest cost resource capable of providing electricity to a utility. Even under a revised methodology that would value the benefits of load-proximate generation, PURPA specifies that avoided cost rates must remain indifferent to generation source if they are not developed pursuant to a technology-specific state mandate. This fact could allow avoided cost rates to be set at a level that does not facilitate growth in all distributed QF technologies. On the other hand, recent installation and technology cost declines may allow distributed QFs to be financially viable at lower payment levels than was possible a few years ago.

b) What Size of Distributed QF Would be Eligible?

In the promulgation of PURPA regulations, FERC recognized the benefits of standard rates for small generators and required states and non-regulated utilities to develop standard rates for purchases from QFs 100 kW or less.[50] Several parties commented that systems larger than 100 kW would also benefit from standard rates, since they would otherwise face steep transaction costs associated with individually calculating the rate for each project in a contract with the utility.[51] In response to these comments, FERC revised its regulations to allow states and non-regulated utilities the option to voluntarily develop standard rates for QFs above 100 kW pursuant to the must-buy obligation.[52] For a value-based PURPA rate to be effective in facilitating distributed QF growth, it will be necessary for a standard rate to be

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50 *See, e.g.,* FERC Order No. 69, 45 Fed. Reg. 12214 at 12223; 18 C.F.R. § 292.304(c)(1).

51 *Id.*

52 18 C.F.R. § 292.304(c)(2).

available to larger QFs. In California, the average-sized solar photovoltaic system installed by large commercial customers is currently 246 kW[53] and average system sizes nationally have been trending upwards.[54] The current threshold of 100 kW for a standard rate under PURPA is therefore not adequate to support a significant portion of the existing market for solar photovoltaic system installation in the United States.

c) What About Small Utilities?

As mentioned earlier, PURPA only applies to utilities that sell over 500,000 MWh per year, so it does not include smaller utilities. A PURPA-based approach is also relevant in states with restructured markets. While PURPA would not apply to retail choice suppliers, the obligation to purchase from QFs would still apply to the local utility providing distribution services.[55] However, smaller utilities and retail choice suppliers could opt into a value-based approach.

d) Tax Implications

An avoided cost payment may result in taxable income. By comparison, electricity that is used for personal consumption is not taxable income, which underscores the importance of allowing consumers with onsite energy needs to use generation onsite versus requiring that all onsite generation be sold to a utility at an avoided cost rate. Allowing onsite electricity use reduces the portion of output that would be needlessly subject to income tax.

e) Administrative Difficulty in Determining QF Pricing

Determining the price level of a utility's avoided cost can be difficult and state rulemakings aimed at determining avoided cost can be contentious. The possible creation of a complicated, location-specific calculation could take a long time to complete and agree upon. Creating average values is one way around some of the complexity, but even the methods to create those averages may prove controversial. Where avoided costs can be indexed to transparent market costs, such as energy markets, capacity markets, and REC markets, administrative difficulty can be reduced.

f) Utilities Can Seek Relief from PURPA's "Must Buy" Requirements

Utilities have three primary avenues to seek relief from PURPA's must-buy obligations. First, the Energy Policy Act of 2005 allows utilities to apply to FERC to terminate QF purchase obligations where QFs have adequate nondiscriminatory access to transmission and to wholesale markets.[56] For QFs under 20 MW, however, a utility must overcome a rebuttable presumption that QFs lack non-discriminatory

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53 This number is based on the average nameplate capacity of "Large Commercial" customers in the California Solar Initiative database (based on 1/30/13 data). *See* California Solar Statistics, *available at* http://www.californiasolarstatistics.ca.gov/.

54 Larry Sherwood, *U.S. Solar Market Trends 2011* (Interstate Renewable Energy Council), p. 4 (noting that the average system size of solar PV increased by 64% from 2010 to 2011) (July 2012), *available at* http://www.irecusa.org/news-events/publications-reports/.

55 16 U.S.C. § 824a-3(m)(B)(5) (electric utilities have no obligation to sell electricity to QFs where there are competitive retail suppliers willing and able to sell to QFs or where the state does not require the utility to sell electric energy in its territory).

56 16 U.S.C. § 824a-3(m).) (PURPA Section 210(m)).

access to wholesale markets and transmission.[57] Second, PURPA regulations allow utilities to curtail must-buy purchases during system emergencies.[58] Third, FERC rules provide, with certain limitations, that a utility is not required to purchase unscheduled QF energy "during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself."[59] This does not mean that utilities may simply curtail purchases from QFs when they have more economic choices in the marketplace; rather, they may curtail purchases only in limited cases where a utility would be forced to cut back on slow-ramping base-load generation and use more expensive, fast-ramping generation to cover changes in QF generation. Nevertheless, these three avenues exist for a utility to seek relief from PURPA's "must buy" requirements and may undermine an effective PURPA-based approach to supporting DG growth if they are not reasonably limited.

VI. Conclusion

PURPA's original mission was to spur growth in clean energy investment. If the goal is to create markets that facilitate consumer access to new technologies and that drive resource deployment based on the potential benefits to ratepayers, utilities and the grid, then it makes sense to weigh the potential advantages and disadvantages and consider a PURPA-based approach.

Although recent FERC decisions have provided the needed justification to compensate distributed QFs for value provided, the discussion above highlights several issues that would need to be addressed before PURPA could be a viable option for promoting DG growth. These include: 1) ensuring that all DG benefits are appropriately valued in setting a distributed QF rate, 2) increasing the eligibility for a standard QF rate above 100 kW, 3) ensuring the ability for distributed QFs to serve onsite load, 4) prohibiting punitive fees and charges from being imposed on customers that use a QF to serve onsite load, and 5) limiting or removing utility options to curtail must-buy obligations for distributed QFs.

57 18 C.F.R. § 292.309(d)(1). *See Pub. Serv. Co. of New Hampshire,* 131 FERC ¶ 61,027 at P 22 (holding that FERC Order No. 688 and 18 C.F.R. § 292.309(d)(1) require a utility to overcome, on a QF-by-QF basis, the rebuttable presumption that QFs of 20 MW or less lack nondiscriminatory access to wholesale market).

58 18 C.F.R. § 292.307(b).

59 18 C.F.R. § 292.304(f)(1).