UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference on Implementation Issues Under the Public Utility Regulatory Policies Act of 1978 — Docket No. AD16-16-000

The Honorable Travis Kavulla
President, National Association of Regulatory Utility Commissioners, and
Vice Chairman, Montana Public Service Commission
June 29, 2016

On behalf of the National Association of Regulatory Utility Commissioners, I am thankful that you have invited several state utility commissioners here today, since we "play the primary role in calculating avoided cost rates."[1]

In some jurisdictions, the Public Utility Regulatory Policies Act of 1978 (PURPA) is all but a footnote.[2] In others, it takes up an enormous amount of resources on the part of the State commission, the utility, and qualifying facilities (QFs) eligible for avoided-cost rates under the law. I estimate, for the sake of example, that PURPA issues consume more than one-quarter of the time that the Montana Public Service Commission commits to matters of electric utility regulation, even though QFs account for less than one-tenth of the total resources serving the customers of regulated utilities in the state.

I attempt to explain why PURPA still matters in certain regions of the country, and offer some approaches to rationalizing PURPA's associated administrative regulations in these comments.

My written presentation is structured to cover the following topics in turn:

- A discussion of the differences between the marketplace structures for electrical generation across the United States;

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[1] *Indep. Energy Producers Ass'n, Inc. v. Cal. Pub. Utils. Comm'n*, 36 F. 3d 848, 856 (9th Cir. 1994).
[2] 16 U.S.C. § 824a-3 (2012).

- Methods of measuring avoided cost in those places where PURPA still occupies a prominent place on state commissions' dockets;
- Common problems and debates in the measurement of avoided cost; and,
- Potential ideas for reform.

Regional Differences

PURPA is implemented in dramatically different ways across the United States. These differences appear mainly to result from the fact that there are, broadly speaking, three different types of marketplaces in which generators seek revenues in the United States.

- There are those regions where it is expected that the centrally clearing markets of an RTO/ISO will provide adequate revenues through their settlements to procure sufficient amounts of energy and capacity to serve customer load in both the short term and long term.
- There are those places which have centrally clearing markets for energy and, perhaps, for capacity, but where those markets play more of an optimizing function than a long-term procurement function. Load-serving utilities either own most generation in such regions, or they contract for it in long-term power purchase agreements (PPAs). Generation in these markets, with the exception of QFs, typically results from a central-planning decision on the part of the utility and its regulator that it is the least-cost method in which to serve customer load. Consumer rates are fixed based on the cost to the utility of those generators, whether owned or contracted, and market clearance acts as a revenue credit or surcharge on top of the fundamentally cost-of-service paradigm.
- Finally, there are those utilities, as above, that own or contract for the vast majority of their customers' needs (or in excess of them, such as those utilities in the Northwest that market excess hydro capacity) and who rely not on RTOs/ISOs, but on bilaterally transacting wholesale markets for the disposal or purchase only of the surplus or deficits of their energy and, sometimes, capacity needs.[3] In other words, they self-schedule their generation without an optimizing function or a particularly liquid wholesale price signal.

Commissioner Raper of Idaho will speak to the need for FERC to continue to ensure that flexibility is available to the States in establishing measures of avoided cost. My remarks will focus on avoided-cost methodologies.

Whether compensation for a QF is a matter of market clearing prices or of administrative decision-making is largely a reflection of how larger or utility-owned generation is compensated.

[3] Except for perhaps the Southeast, each of the regions of the country has at least two of these business models operating simultaneously and, periodically, in tension with one another.

In the Western Interconnection, it is typical for regulated utilities to "rate-base" their generating assets, with rates established to permit the capital investment in those plants to be returned through depreciation expense, an annual return on the undepreciated balance of investment, and operating costs. These rates provide a long-term revenue guarantee—or something close to it—to the utility, irrespective of whether the plant, in the long run, will have been an above-market or below-market investment. Utilities instead rely on a central-planning exercise typically known as Integrated Resource Planning (IRP) to make a judgment at the outset, relative to a long-term market forecast and a survey of available alternatives, that the investment is efficient compared to alternatives. Regulators either bless IRPs, conferring a signal for the likelihood of cost recovery, or pre-approve new plants directly, or grant them "rate base" status shortly after their construction. Most state regulators in the Western Interconnection traditionally have offered QFs a similar opportunity for long-term contracts.[4]

Other utilities are permitted to include generation in their cost-of-service rates, but also participate in the energy markets of an RTO.[5] In these markets, there is a rebuttal presumption that QFs with a capacity larger than 20 megawatts (MWs) have access to whatever market the RTO operates, bidding from the node nearby which they are interconnected.[6] In the marketplace without an RTO, a QF would have to rely on scheduling transmission over one or more Open

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4 This tradition appears to be changing somewhat, with some regulatory commissions limiting the tenor of QF contracts. Idaho's commissioners speak to this in their pre-filed remarks. The reasons for this change are described in their comments, as well as in the below section on debates on avoided-cost methodologies.

5 Montana has both examples. NorthWestern Energy's Montana-regulated customers are served under a retail monopoly and have that company's resources dispatched through a transmission system that it owns and operates, in order to serve that native load. Montana-Dakota Utilities (MDU), meanwhile, does business in the Eastern Interconnection and is a transmission-owning member of Midcontinent Independent Transmission System Operator (MISO), which operates MDU's transmission and an energy market into which MDU bids all of its owned generation.

6 18 C.F.R. § 292.309(e) & (f) (2016). The rebuttal presumption applies to MISO, PJM Interconnection, L.L.C., ISO New England, Inc., New York Independent System Operator, and the Electric Reliability Council of Texas, but not the California Independent System Operator and Southwest Power Pool, Inc. *Id*.; 18 C.F.R. § 292.309(g) (2016).

Access Transmission Tariffs (OATT) of incumbent utilities and even so would have to rely on a purchaser in the bilateral wholesale market to offtake that generation. In other words, a counterparty is never a sure thing in that example, while there is *always* a purchaser for a QF's energy when its bid is below the market clearing price in an RTO. This does not solve the controversy over payment for capacity, or a contract that is based on a long-term projection of avoided cost. It is nonetheless a guarantee of market access.

Meanwhile, in restructured states, where generators cannot avail themselves of the revenue protections of cost-of-service regulation, QFs have instead been expected to compete on the same market prices that are the vehicles for compensation of incumbent generators. The treatment of QFs which are denied long-term contracts by States in such a situation is, essentially, identical to other generators.

Avoided-Cost Methodologies

The dominant methodologies for measuring avoided cost under PURPA have been well-developed for some time, and recently have been memorialized in a manual co-published by NARUC, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association.[7]

The most frequently used long-term avoided-cost calculation methodologies are:

Proxy resource method & peaker/component method. Sometimes regarded as two different methodologies, these are two different ways of looking at the resources that a QF avoids as a basis for compensating a generator under PURPA. A utility IRP typically identifies the marginal energy and/or capacity resource the utility intends to own or contract with. This

[7] Robert E. Burns & Ken Rose, "PURPA Title II Compliance Manual" (March 2014), available online at: https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC.

resource is then used as a proxy for creating an avoided-cost stream into the future based on the projected costs of the resource.

A blend of market price forecasts and the proxy resource method is how the Montana PSC and other commissions in the West have often calculated long-term avoided-cost rates. A combined cycle gas turbine (CCGT) is used as a proxy resource, with the capital costs associated with a simple cycle gas turbine (SCGT) subtracted from it. Those capital costs become a proxy for capacity costs which the QF, depending on its capacity contribution, will be awarded. The remaining costs of the facility, including projected operating costs, become the avoidable energy costs which the QF is awarded. Until the projected online date of the CCGT, an electricity market price forecast for one of the Western Interconnection’s bilateral trading hubs is used to project the value of energy deliveries from the QF. Together, this avoided-cost stream is levelized over the term of the contract.

Differential revenue requirement method. This is another methodology suited to utilities that use IRP-based generation planning. It uses a portfolio model to add, as if cost-free, the production of a QF, which will result in a lower net present value (NPV), or annual revenue requirement, than the utility-planned portfolio. The purpose of this undertaking is to rely on the model to identify the energy and capacity that QF displaces in a holistic manner. The difference in the NPV or revenue requirement is then assigned as the avoided cost for purposes of compensating the QF. As portfolio models grow more sophisticated and nuanced about the relative contributions of different resources, it is likely the use of this methodology will increase.

Market-price index or wholesale clearing prices. This method either uses an index to compensate QFs, or relies on wholesale clearing prices of RTOs. This data is often an input to the above methodologies, but can be used on a standalone basis. It provides variable compensation to the QF, even if contracted for the long term. QFs regard this method as lacking parity with utility-owned generation, which, as explained above, is provided revenue regardless of the market price of electricity.

Common Debates and Problems in Avoided-Cost Methodologies

Many dilemmas have presented themselves in recent years concerning the calculation of avoided cost. I do not purport to present a complete list, but below are major challenges that Western state regulators have recently faced.

Contract length and the risk associated with long-term projections of avoided cost. To the degree that the electricity or natural gas price forecasts that are central to avoided-cost methodologies overstate the likely price of those things at wholesale, a longer term contract will exacerbate that error.

The mismatch between haphazard QF additions and integrated resource planning. The central planning exercise that still dominates many parts of the country has at its core the assumption that the least-cost, least-risk portfolio is one that is planned holistically, even if competitive solicitation is used to procure the resources that are selected as optimal in the IRP. While QF rates in the above methodologies may flow from the IRP, they are unavoidably inelegant approximations of avoided cost, because while they assume that the proxy or peaker resources will actually be deferred, this may or may not occur. Imagine, hypothetically, that a certain amount of QF resources come online under “proxy resource” avoided-cost rates, but not enough to displace a CCGT from being necessary. It might be inefficient to scale down such a plant, but also unwise to further defer its construction; in this scenario, a QF might have been compensated on the basis of an avoidable resource that never ends up being avoided.

Standard rates vs. project specific rates. This difficulty may be avoided by establishing a project-specific rate, on the basis that the avoided resource may be more precisely identified and measured. However, in order to eliminate transactional frictions, state commissions have often used standard-offer rates, where a QF under a particular size is eligible for published rates established periodically through a generic docket.[8] These rates provide certainty to all parties, but also can become quickly out-of-date and prompt developers to abandon efficiencies of scale, or to offer many cookie-cutter projects of a smaller size, in order to avoid a more specific and timely calculation of avoided cost, even while contributing significantly more resources to the system than was anticipated when these standard rates were set. Many states have reduced standard-offer eligibility; in 2013, it was reduced from 10 to 3 MWs of nameplate capacity in Montana.

Competitive solicitations. Several state commissions have used competitive solicitations or auctions to procure generation, including resources that otherwise would have qualified as QFs. This allows price discovery in a process that is not administratively determined, however it may not fulfill PURPA's requirement that a utility take the output of a QF.[9] Solicitations could be offered more frequently and be more inclusive, but the practice might then cut against the grain of the IRP's identification of particular resources.

Utility's need for resources in a low-growth environment. One of the proximate causes of the uptick in PURPA conflicts recently is no doubt that utilities simply need fewer additional resources than they once did, and the resources that they do need often have particular characteristics—such as flexibility—which an administratively determined avoided-cost process is ill-suited toward. In such a context where utilities do not require additional energy to serve

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8 18 C.F.R. § 292.304(c) (2016).

9 *Hydrodynamics*, 146 F.E.R.C. 61,193 (March 20, 2014).

native load, and where even many or all of their thermal or steam resources have been dispatched down, should the avoided cost simply match a market price projection (on the assumption that the utility acts as a reseller of this supply into the wholesale market) or should it be assigned an avoided cost of zero to represent the lack of need?

Other debates have included how to value the environmental attributes of QFs (to the degree they do not qualify as energy and capacity under PURPA), how to consider curtailment of resources, and how to assign QFs a capacity value.

Potential Ideas for Reform

The twin goals of PURPA are "to encourage wholesale competition in electric generation" and "to increase the use of renewable energy resources and cogeneration for wholesale power supply."[10] The second of these goals has been unambiguously accomplished. The first is perhaps a work in progress, and PURPA is a blunt instrument to encourage such reform—and secondary compared to FERC's own landmark rulings such as Order 2000[11] and Order 888,[12] as well as to state commissions' insistence on cost discipline and competition within the framework of their regulatory oversight.

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10 *Resolution on Legislation to Reform 210 of The Public Utility Regulatory Policies Act of 1978*, NARUC (adopted July 26, 1995) at 1, available online at: http://pubs.naruc.org/pub/5397D0E8-2354-D714-511B-790DCDD6D988 (NARUC Resolution).

11 Order No. 2000, *Regional Transmission Organizations*, FERC Stats. & Regs. ¶ 31,089 (1999), 65 Fed. Reg. 810, on reh'g, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092, 65 Fed. Reg. 12,088 (2000), petitions for review dismissed, *Public Utility District No. 1 of Snohomish County v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

12 Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs. ¶ 31,036 (1996), 61 Fed. Reg. 21540 (May 10, 1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000) (TAPS v. FERC), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

NARUC has recognized this by advocating, as it does today, that PURPA's mandatory purchase obligation should not exist "in any state which has made a finding that the acquisition of generating capacity is subject to competition or other acquisition procedures such that the public interest is protected with respect to price, service, reliability and diversity of resources."[13] Likewise, NARUC has resolved that each State commission should encourage "the competitive acquisition of wholesale power supplies."[14]

It follows that it would be preferable for FERC to adopt regulations that attempt to move away from the use of administratively determined avoided costs to their measurement through competitive solicitations or market clearing prices. While the range of FERC's potential is limited by PURPA itself, FERC could adopt interpreting regulations that relax either the mandatory purchase obligation or make it clear that shorter-term avoided-cost calculations are acceptable for PURPA compliance in certain circumstances:

- Where solicitations are routinely held and genuinely competitive for the needs identified in a utility's IRP; or,
- Where a utility, in its IRP, does not forecast the need for an additional owned or long-term-contracted energy resource for the next 5 or 7 years; or,
- Where a real-time energy market is operational, and where clearing prices and/or bids in that market are not subject to market-power mitigation to cost.

NARUC has not proposed specific solutions in relation to FERC's notice of this technical conference, but the above are at least ideas around which such a conversation might begin. My association would be happy to consider various proposals that FERC publishes.

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[13] NARUC Resolution at 2.

[14] *Id*. at 2.