UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facility Rates and Requirements	)	**Docket Nos. RM19-15-000**
	)	
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	))	**AD16-16-000**

COMMENTS OF THE
AMERICAN PUBLIC POWER ASSOCIATION AND
THE LARGE PUBLIC POWER COUNCIL

I. BACKGROUND AND SUMMARY OF POSITION

The American Public Power Association ("APPA") and the Large Public Power Council ("LPPC") submit these comments in support of the proposals contained in the Notice of Proposed Rulemaking issued in these dockets by the Federal Energy Regulatory Commission ("FERC" or "the Commission") on September 19, 2019.[1] The NOPR proposes to revise the Commission's regulations[2] implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") requiring electric utilities to purchase electric energy from qualifying small power production and cogeneration facilities.[3]

A. APPA and LPPC

APPA is the national service organization representing the interests of not-for-profit, state, municipal, and other locally owned electric utilities in the United States. More than 2,000 public power systems provide over 15 percent of all kilowatt-hours sales to ultimate customers and serve over 49 million people, doing business in every state except Hawaii.

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[1] *Qualifying Facility Rates and Requirements*, Notice of Proposed Rulemaking, 168 FERC ¶ 61,184 (2019) ("NOPR" or "Proposed Rule").

[2] 18 C.F.R. Part 292.

[3] 16 U.S.C. § 796(17)-(18), 824a-3.

LPPC represents 27 of the largest state and municipally-owned utilities in the nation. LPPC's members are located throughout the nation, both within and outside the boundaries of regional transmission organizations ("RTOs") and independent system operators ("ISOs"). The members comprise the larger, asset-owning utilities in the public power community, owning approximately 90 percent of the transmission assets owned by non-federal public power entities. LPPC members are also members of APPA.

As utilities owned by state and municipal entities, APPA and LPPC members are exempt from most features of Federal Power Act ("FPA") regulation under section 201(f) of the FPA.[4] Though defined as non-public utilities under the FPA, APPA and LPPC members nonetheless are "electric utilities," subject to section 210 of PURPA and the obligation to "purchase . . . any energy and capacity which is made available from a qualifying facility."[5] Non-public utilities have recognized their obligation to purchase power from Qualifying Facilities ("QFs") under PURPA section 210 since the statute's inception.[6]

B. Summary of Position

APPA and LPPC agree with the Commission that the transformation of the electric industry in the 40 years since promulgation of the PURPA regulations in 1980 justifies significant changes in the regulations. The development of competitive markets, both within and outside RTOs/ISOs, and the dramatic growth of a renewable power sector now largely independent of the boost once provided by PURPA are the most salient of these changes.[7]

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[4] 16 U.S.C. § 824(f).

[5] 18 C.F.R. § 292.303(a).

[6] Section 210(f) of PURPA specifies that nonregulated electric utilities must implement the Commission's rules, as must State regulatory authorities. 16 U.S.C. § 824a-3(f). Consistent with the approach used in the NOPR, both "nonregulated electric utilities" and "State regulatory authorities" are referred to collectively and hereinafter as "State Regulatory Authorities." *See* NOPR at P 4; *see also id.*, P 36 n.60.

[7] *See* NOPR at PP 19-27.

The Commission's proposed reliance on market forces as a touchstone for its proposed reforms is well-supported. APPA and LPPC agree that State Regulatory Authorities should be explicitly authorized to rely on the marketplace in setting prices for QF power sales under the PURPA framework. This market-based approach sensibly supports reforms making clear that State Regulatory Authorities may employ market-based energy prices in setting avoided energy costs. It further supports the use of competitive solicitations to establish avoided energy and capacity costs, and the decision to enable State Regulatory Authorities to move away from locked-in energy costs for the life of QF obligations. APPA and LPPC particularly appreciate the Commission's proposal to authorize, but not to compel, State Regulatory Authorities to employ the avoided cost methodologies described in the Proposed Rule. The continued discretion and flexibility afforded State Regulatory Authorities is consistent with the approach to cooperative federalism that underlies PURPA itself.

APPA and LPPC also believe there is strong support for the Commission's conclusion that the availability to QF developers of options in the competitive marketplace supports further reasonable limits on the PURPA purchase obligation. The Commission's proposals in this respect reflect a reasonable evolution in the administration of the exceptions outlined by Congress in PURPA section 210(m).

Finally, APPA and LPPC endorse the Commission's proposals to strike a more appropriate balance between promoting certainty in the QF qualification process and allowing interested parties to raise valid QF eligibility concerns. The sensible reforms proposed for the Commission's current "one-mile rule" would likely eliminate most of the gaming concerns that have arisen under the current regulations while ensuring adequate regulatory certainty for genuine small power production QFs. Likewise, allowing interested parties to protest a QF's self-certification or self-recertification without filing a petition for declaratory order would properly acknowledge the important notice and monitoring function played by Form No. 556 submissions.

II. THE NEED FOR REGULATORY REVISIONS

A. Dramatic Changes in Electric Markets Support the Case for Regulatory Reform

The Commission is right to point to overwhelming change in the electric marketplace since the passage of PURPA in 1978 and the promulgation of FERC's implementing regulations in 1980. An electric market dominated in 1978 by vertically integrated utilities and negligible renewable generation has been transformed substantially. Growth in the non-utility generating sector has been dramatic since 2005, with total nation-wide figures escalating from 51.7 TWh in 2005 to 340 TWh in 2018, spread across RTO and non-RTO regions.[8]

Specifically as to renewable development, as the Commission reports, Energy Information Administration ("EIA") data show that in 2019, fully 65% of additional generating capacity will come from renewable resources, while 22% of installed capacity as of July 2019 comprised renewable resources (including hydroelectric capacity).[9] While PURPA at its inception was certainly a substantial driver for the development of the Independent Power Producer ("IPP") sector, its relevance in recent years has waned, with only 10-20% of all currently operating renewable resources classified as QFs.[10] A 2018 EIA analysis reported that "[b]etween 2008 and 2017, more than 103 gigawatts (GW) of renewable generating capacity entered service in the United States, of which only 14 GW is certified to have qualifying facility

[8] NOPR at P 27.

[9] NOPR at PP 21-22.

[10] NOPR at PP 22, 74, citing EIA data.

small power producer status under" PURPA.[11] Recent projections by Wood Mackenzie, moreover, indicate that PURPA is the primary driver for just 2% of the utility scale PV capacity currently in development, with voluntary procurement (61%), renewable portfolio standards ("RPS") (18%), and retail procurement (16%) constituting much bigger drivers.[12]

This shift in factors driving renewable development is substantially attributable, as the NOPR recognizes, to state-mandated RPSs, along with other financial incentives and measures pressing for greenhouse gas reductions.[13] These mandates have been supplemented by regional initiatives such as the Regional Greenhouse Gas Initiative ("RGGI") and California's Greenhouse Gas Initiative. As the Commission notes, 29 states have mandatory RPS programs.[14]

APPA and LPPC member experience certainly supports the Commission's view of the breadth of changes the industry has experienced since 1980, and the driving factors. In total, 16 of the 21 states in which LPPC members operate[15] have established substantial RPS requirements, renewable or clean energy standards or goals.[16] The most rigorous of these are California (RPS mandating 60% renewable energy by 2030, and 100% clean energy by 2045), Colorado (renewable energy standard calling for between 10% and 30% renewable energy, and a

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[11] EIA, Today in Energy, *PURPA-qualifying capacity increases, but it's still a small portion of added renewables* (Aug. 16, 2018), available at: https://www.eia.gov/todayinenergy/detail.php?id=36912.

[12] Wood Mackenzie Power & Renewables forecasts at p. 16 (July 2019), available at: https://www.woodmac.com/our-expertise/focus/Power--Renewables/renewables-forecasts-h1-2019/.

[13] NOPR at P 20.

[14] NOPR at P 23.

[15] *See* https://www.lppc.org/who-we-are/our-members.

[16] *See* Nat'l Conf. of State Legislature, State Renewable Portfolio Standards and Goals (Nov. 1, 2019), *available at* http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx. Such states include Arizona, California, Colorado, Delaware, Indiana, Maryland, Michigan, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Virginia, and Washington. Public power utilities are subject to the RPS standards or goals, in whole or in part, in many of these states, including California, Colorado, Michigan, New York, North Carolina, Oklahoma, and Washington.

goal of 80% reduction in carbon emissions over 2005 levels by 2030 and 100% clean energy by 2050 for qualifying retail utilities); and New York (RPS mandating 50% renewables by 2030).[17] It is also worth reporting that certain of the APPA and LPPC members have exceeded state-based renewable requirements.

As well, the Commission is correct in pointing out that an abundance of relatively inexpensive natural gas resources distinguishes the current environment from the one facing the Commission in 1980. The energy picture that animated the passage of PURPA in 1978 included gasoline and natural gas shortages leading Congress to conclude that alternative technologies were a critical factor in enabling the nation to meet its energy needs. The shale revolution in the natural gas production industry very evidently alters that picture, again calling for a fresh view of the 1980 regulations.

This changing landscape also includes a dramatic drop in the cost of renewable generation.[18] Recent reports indicate that over the past decade, the levelized cost of electricity on a megawatt-hour basis for onshore wind and photovoltaic solar has fallen, respectively, by 49 percent and 84 percent.[19] These price drops substantially buttress the market position of renewable generation, and weaken the rationale for the current breadth of the purchase mandate.

Turning to the demand side of the equation, the development and expansion of RTOs and ISOs throughout much of the country, closely following the implementation of the open access framework under Order No. 888, created competitive alternatives for the sale of QF power.

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[17] *Id*.

[18] NOPR at P 20.

[19] BloombergNEF, *Battery Power's Latest Plunge in Costs Threaten Coal*, Gas (March 2019), available at: https://about.bnef.com/blog/battery-powers-latest-plunge-costs-threatens-coal-gas/.

PURPA section 210(m) was crafted expressly to respond to these developments, though the Commission's current regulations do not do so to the full extent permitted by the statute.[20]

B. PURPA Section 210 Requires the Commission to Revisit Its Regulations

Section 210(a) of PURPA specifies that the Commission "shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production. . ."[21] By its terms, the statute calls for the Commission to respond to changing industry and market conditions by periodically revisiting its regulations implementing PURPA, precisely what the Commission proposes to do here in its NOPR. The Commission's rules implementing PURPA need not, and cannot, remain fixed, but must evolve with the Commission's consideration of the environment in which its regulations operate. The Commission is well-justified, therefore, in proposing to "rebalance" the approach to PURPA implementation that it adopted in 1980.[22]

The Supreme Court's 1983 decision in *American Paper Institute v. American Electric Power Corp*, 461 U.S. 402 (1983) ("*API*"), underscores this conclusion. There, the Court upheld the Commission's decision to set compensation for QFs at "maximum avoided cost," deferring to the Commission's considerable discretion under the statute, exercised "in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the nation's dependence on fossil fuels."[23] The Court's ruling took into account the nascent stage of renewable energy and cogeneration development under PURPA and suggested that, with the passage of time or

[20] NOPR at P 26.

[21] 16 U.S.C. § 824a-3(a).

[22] NOPR at P 31.

[23] *API*, 461 U.S. at 417.

changed circumstances, the Commission might be justified in adopting a different approach.[24] Indeed, the Court specifically noted that "the full-avoided cost rule is subject to revision by the Commission as it obtains experience with the effects of the rule . . . ."[25] With the development of renewable power and non-utility generation well under way, driven by factors largely independent of PURPA, and with the nation's abundance of natural gas resources, the conditions animating the rule under review in *API* have obviously changed dramatically. Given the extensive record of these changes, there is no doubt that the deference to the Commission's judgment extended by the Court in *API* supports the Commission's NOPR.

To be sure, the Commission's regulations under PURPA still must aim "to encourage cogeneration and small power production."[26] But, as the Supreme Court's ruling in *API* and the statute itself make clear, the Commission, in assessing what is necessary to "encourage" these resources, may take into consideration current circumstances and tailor its regulations accordingly. As APPA and LPPC discuss below, the proposals contained in the NOPR would properly implement the Commission's obligation to encourage cogeneration and small power production, taking into account the profound industry changes since 1978.

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[24] *See id.* at 417 (finding that "[t]he Commission's order makes clear that the Commission considered the relevant factors and deemed it most important *at this time* to provide the maximum incentive for the development of cogeneration and small power production . . . .) (emphasis added); *see id.* at 417-18 (observing that "*[a]t this early stage in the implementation of PURPA*, it was reasonable for the Commission to prescribe the maximum rate authorized by Congress and thereby provide the maximum incentive for the development of cogeneration and small power production.") (emphasis added).

[25] *Id.* at 416.

[26] 16 U.S.C. § 824a-3.

III. COMMENTS ON SPECIFIC NOPR PROPOSALS

A. QF Rates (NOPR, PP 32-42)

APPA and LPPC welcome the suite of proposed changes that would ensure that State Regulatory Authorities are not limited to administratively determined avoided costs and may rely on market forces in pricing utility purchases from QFs. To a substantial degree, the proposed changes have been presaged by Commission precedent over the past several years, with the widespread development of market alternatives for the purchase and sale of energy.

The Commission is right in emphasizing that its administration of PURPA section 210 has always afforded state regulatory authorities "great latitude" in determining how to implement the Commission's rules.[27] And it is clear on the face of the statute itself (in terms repeated in the Commission's regulations),[28] that "the incremental cost to the electric utility of alternative electric energy" provides the flexibility to use market alternatives as a measure of avoided cost, where those alternatives exist.[29] As the Commission notes, some State Regulatory Authorities already rely on competitively-set prices to establish avoided costs – such as the use of a locational marginal price ("LMP") as a measure of an electric utility's avoided cost energy rate.[30] The Commission should make clear that, while the NOPR provides greater clarity as to State Regulatory Authorities' entitlement to rely on competitively-set prices as a measure of avoided cost rates, nothing in the Proposed Rule is intended to call into question State Regulatory Authorities' existing implementation of PURPA's avoided cost requirements.

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[27] NOPR at P 35, citing Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,891-92. *See also Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC ¶ 61,304, at 61,646 (1983).

[28] 18 C.F.R. § 292.101(b)(6).

[29] 16 U.S.C. § 824a-3(b).

[30] *See* NOPR at P 50.

APPA and LPPC agree with the Commission's tentative conclusion that pricing in competitive markets both in and outside RTOs/ISOs, offers a practical set of alternatives to the process of setting avoided costs administratively. The Commission's proposed reforms would make clear that State Regulatory Authorities possess appropriate flexibility to address above-market QF costs. APPA has increasingly heard from its members that PURPA's mandatory purchase obligation has required them to buy QF power they do not need, often at rates that are higher than what can be obtained from the market. The substantial discrepancy between market prices and administratively determined avoided costs has been the measure of the uneconomic nature of many PURPA agreements. Reforms making clear that State Regulatory Authorities can rely on market pricing in setting avoided cost will ensure that they may opt for sensible market-oriented solutions, reflecting the cost of pricing alternatives available to purchasing utilities.[31]

1. Locational Marginal Price as a Permissible Rate for Certain As-Available QF Energy Sales (NOPR, PP 43-49)

The Commission proposes to add subsections (b)(6) and (e)(1) to section 292.304 of its regulations in order to make clear that State Regulatory Authorities may set the as-available energy rate paid to a QF by an electric utility located in an RTO/ISO at LMP, calculated at the time of delivery.[32] Observing that LMP reflects the market-clearing price received by all sellers

[31] NOPR at P 40.

[32] As the Commission explains, some State Regulatory Authorities already use LMP as a measure of avoided cost, and, thus, this aspect of the NOPR is more in the nature of clarification that "a state would be able to adopt LMP as a per se appropriate measure of the as-available energy component of avoided costs." NOPR at P 50 (footnote omitted); *see also, e.g.*, *Windham Solar LLC*, 157 FERC ¶ 61,134, at P 5 (2016) (indicating that setting avoided cost based on the real-time energy price in ISO-NE "is the type of rate within the scope of section 292.304(d)(1) of the Commission's regulations" addressing as-available sales).

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and paid by all buyers in a Day-2 RTO/ISO market,[33] the Commission "preliminarily finds that LMP is an accurate measure of avoided costs."[34]

APPA and LPPC support the proposal for the reasons offered in the NOPR. As the Commission comments, the LMP framework is designed to foster more efficient use of the transmission grid by reflecting the cost of generation redispatch in real-time pricing signals.[35] These signals reflect prices available to utilities purchasing power in the market, as active market participants. And, as the Commission represents, Congress's determination in PURPA section 210(m) that the purchase obligation may be terminated by utilities in organized markets (upon the Commission's determination that QFs have appropriate access) reflects the judgment that pricing available to QFs in these markets is a viable alternative to the purchase obligation under section 210.[36] It stands to reason, accordingly, that LMP pricing available to QF sellers and utility purchasers is a reasonable measure of avoided cost.

APPA and LPPC recognize that the administration of LMP pricing is a complicated matter, with the LMP methodology setting prices in Day-Ahead and Real-Time markets, settlements reflecting actual market results, adjustments needed in order to reflect actual results, and hedging through the use of Firm Transmission Rights. Under proposed section 292.304(b)(6) of the regulations, these nuances would be administered at the state and local level, as currently are the myriad of other options available to States Regulatory Authorities in establishing avoided costs under existing regulations. What matters here is the recognition that LMP pricing reflects the real cost of alternative energy, and that State Regulatory Authorities

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[33] NOPR at P 44.

[34] NOPR at P 45.

[35] NOPR at P 48.

[36] NOPR at P 49.

should be expressly authorized to use this measure in establishing avoided costs, consistent with the statute.

2. Use of Other Competitive Prices as Permissible Rates for Certain As-Available QF Energy Sales (NOPR, PP 51-59)

The Commission proposes to amend section 292.304(b)(7) and to add new subsection (e)(1) to specify that State Regulatory Authorities have the flexibility to set QF energy rates for sales to electric utilities located outside RTO/ISO markets based on "Competitive Prices" (a new defined term). The Commission proposes changes to the regulations that would explicitly permit State Regulatory Authorities to rely on Market Hub Prices (*i.e.*, prices set at a liquid market hub) available to QFs, or on a Combined Cycle Price (*i.e.*, a price based on a proxy combined cycle generating unit) in specified circumstances, as determined by State Regulatory Authorities.[37] The Commission also notes that there may be other approaches to competitive pricing for as-available energy QF sales.[38]

APPA and LPPC embrace these changes to the regulations. Where market alternatives are available to the purchasing utility, logic strongly suggests that they will meet the statutory definition of avoided cost – *i.e.*, "the incremental cost to the electric utility of alternative electric energy."[39] With respect specifically to Market Hub Prices (NOPR P 56), APPA and LPPC endorse FERC's list of factors in determining whether a hub can serve as a proxy, *viz.,* (1) whether the hub is sufficiently liquid; (2) whether prices are transparent; (3) whether the electric utility has the ability to deliver power from such hub to its load; and (4) whether the hub represents an appropriate market to derive an energy price, given the electric utility's physical

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[37] NOPR at P 51.

[38] NOPR at P 60.

[39] 16 U.S.C. § 824a-3(b).

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proximity to the hub.[40] These factors are sensible and appropriately broad, since the regulatory framework leaves to State Regulatory Authorities the responsibility to administer them.

APPA and LPPC further support the Commission's comment that in establishing express options for the consideration of avoided cost in section 292.304(b)(7) of the proposed regulations, it does not intend to foreclose the authority currently invested in State Regulatory Authorities to establish other means of determining competitive alternatives that would provide a measure of avoided costs.[41] As the Commission "observes…electric utilities may purchase energy at market-oriented prices other than those that would qualify under the standards identified above."[42] The Commission itself notes that competitive solicitations offer one such means of establishing avoided energy costs.[43] For that reason, APPA and LPPC recommend that the prefatory language in proposed § 292.304(b)(7) of the regulations be amended as follows:

> (7) *Competitive Price*. A state regulatory authority or nonregulated electric utility may use a Competitive Price as a rate for as-available qualifying facility energy sales to purchasing electric utilities located outside a market defined in § 292.309(e), (f), or (g). A Competitive Price may be either a Market Hub Price, ~~or~~ a Combined Cycle Price, or a price of comparable competitive quality. Market Hub Price and Combined Cycle Price will be determined as follows:

Amending the proposed regulation in this fashion would also enable utilities proximate to (or embedded within) RTO/ISO markets to reference prices in those markets as viable alternatives in establishing avoided costs. Transmission costs incurred to and from an RTO/ISO

[40] NOPR at P 57.

[41] "The two options presented above are not intended to supersede the states' existing ability to set as-available energy rates based on an electric utility's avoided costs." NOPR at P 60.

[42] NOPR at P 60.

[43] NOPR at P 60, n. 94.

market may be a factor in establishing such state-based avoided cost determinations, but that is not a conceptual objection to this approach.[44]

3. Permitting the Energy Rate Component of a Contract to be Fixed at the Time of the Legally Enforceable Obligation ("LEO") Using Forecasted Values of the Estimated Stream of Market Revenues (NOPR, PP 61-62)

The Commission proposes to add a new provision in section 292.304(d)(1)(iii) explicitly permitting fixed energy rates to be based on forecasted estimates of the stream of revenue flows during the term of the contract. As the Commission puts it: "States may rely on market estimates of forecasted energy prices at the times of delivery over the anticipated life of the contract – such estimates are commonly referred to as a forward price curve – to develop a fixed energy rate component for that contract when such estimates reflect the purchasing electric utility's avoided costs."[45]

APPA and LPPC endorse this proposed change as a logical extension of the conclusion that market options are a legitimate alternative means of specifying avoided costs.

4. Providing for Variable Energy Rates in QF Contracts (NOPR, PP 63-81)

The Commission's proposed revisions to section 292.304(d) of the regulations would permit State Regulatory Authorities to limit a QF's option to fix at the outset of a LEO the energy rate for the entire length of its contract, and instead allow the state to require QF energy rates to vary during the term of the contract. This revision would modify what has been commonly referred to as the "lock in" rule entitling QFs to fix their avoided energy costs for the life of an LEO at the time the obligation is incurred. The Commission further proposes to

[44] As the Commission comments, "…the market hub price may need to be subject to adjustments to account for transmission costs the electric utility would incur before such prices could serve as a factor in determining appropriate QF rates." NOPR at P 58.

[45] NOPR at P 61.

continue to permit QFs to lock in avoided *capacity* costs calculated and fixed at the time the LEO is incurred.[46]

APPA and LPPC support the proposed change to the rule. It is, to begin with, quite clear that the discrepancy between administratively set, locked-in, long-run avoided costs and actual market prices for the purchase of equivalent energy can be enormous.[47] In comments cited by the Commission,[48] the Edison Electric Institute ("EEI") offered evidence that this discrepancy could cost consumers billions of dollars over the next 10-20 years,[49] while evidence to be filed contemporaneously with these comments by EEI indicates an annual over-recovery for a sampling of solar QF agreements between 2013 and 2019 of up to $116.8 million, and an over-recovery for a sampling of wind contracts between 2009 and 2018 of up to $99.4 million, for a total of $3.86 billion.[50]

The cause of this substantial discrepancy is debatable. While the Commission assumed, with the issuance of Order No. 69 promulgating its current PURPA regulations, that over and under-estimations would balance out,[51] the facts are otherwise, possibly due to an under

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[46] NOPR at P 66.

[47] Even in the face of overwhelming evidence that the divergence in any given contract is irreconcilable with actual avoided costs, the Commission has declined to intervene, and the courts have sustained that approach. *See New York State Elec. & Gas Corp, v. Saranac Power Partners, Pub. Serv. Comm'n of the State of New York, et al.*, 117 F.Supp. 2d 211 (N.D.N.Y. 2000); *New York State Elec. & Gas Corp. v. FERC*, 117 F.3d 1473 (D.C. Cir. 1997).

[48] NOPR at P 40.

[49] Docket No. AD16-16-000, Supplemental Comments of the Edison Electric Institute (June 25, 2018). For instance, according to EEI, "[t]he additional price required under long-term fixed contracts will cost PacifiCorp's customers $1.5 billion above current forward market prices over the next 10 years"; and "[m]andating [Idaho Power's PURPA contract] purchases will cost customers an additional $3.5 billion over the next 20 years." *Id*. at 3-4. The data provided by EEI in its Supplemental Comments is derived from a representative survey of certain EEI members.

[50] *See* Concentric Energy Advisors, *An Empirical Analysis of Avoided Cost Rates for Solar and Wind QFs Under PURPA*, at 1 (Nov. 2019) ("Concentric Analysis"), available at: https://ceadvisors.com/publication/an-empirical-analysis-of-avoided-cost-rates-for-solar-and-wind-qfs-under-purpa/.

[51] *See* Order No. 69 at 30,880, cited at NOPR, P 39.

appreciation of the robust development of renewable power driving down marginal cost, and certainly the inability to anticipate the proliferation of inexpensive natural gas resources.

Whatever the explanation for the divergence between actual and projected costs, the question now is whether utility ratepayers should continue to bear the risk of mistaken price forecasts. Were continued development of the IPP and renewable industries in jeopardy, the Commission might have grounds to conclude that enabling QFs to lock in energy payments over the course of their agreement is needed in order to bolster these resources. But the facts are otherwise, and the Commission must take these circumstances into account in rebalancing its PURPA regulations for today's energy landscape.[52]

Further, the record here strongly suggests that locked-in energy costs are not essential in order for QF developers to form the capital needed to sponsor renewable projects. As the Commission points out, QFs now account for only 10-20% of ongoing renewable development.[53] Moreover, much of the renewable development that has occurred over the past 20 years has taken place within RTO/ISO footprints.[54] Development there is largely unaided by PURPA obligations (in view of section 210(m)), and energy prices fluctuate according to the LMP model. It also bears emphasis that PURPA's must-purchase requirement itself should necessarily afford QF developers a degree of certainty; absent an order under section 210(m), a QF has the statutory right to require an interconnected electric utility to purchase the QFs' energy output at avoided cost rates.

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[52] *Cf. API*, 461 U.S. at 417-18 (upholding the Commission's "maximum avoided cost" approach based, in part, on the conclusion that it was a reasonable choice "[a]t this early stage in the implementation of PURPA").

[53] NOPR at P 74.

[54] *See* The Brattle Group, *The Role of RTO/ISO Markets in Facilitating Renewable Generation Development*, at 3, 5-6 (Dec. 2016), available at: http://files.brattle.com/files/5733_the_role_of_rto_iso_markets_in_facilitating_renewable_generation_development.pdf.

Finally, APPA and LPPC note that the Commission does not propose to alter the lock-in rule as it pertains to capacity payments, on the theory that it is appropriate for investors to lock in a revenue stream supporting fixed investments.[55] That proviso substantially ameliorates the impact of the Commission's proposed change.

5. Consideration of Competitive Solicitation to Determine Avoided Costs (NOPR, PP 82-88)

The NOPR also proposes to revise 18 C.F.R. § 292.304 to add subsection (b)(8). In combination with new subsection (e)(1), this subsection would make clear that State Regulatory Authorities have the flexibility to set avoided energy and/or capacity rates using competitive solicitations (*i.e.*, RFPs), conducted pursuant to appropriate procedures. The Commission further proposes a set of minimum criteria that would be employed in determining whether competitive solicitations are sufficiently reliable to serve as a measure of avoided cost. According to the Commission:

> These factors include, among others: (a) an open and transparent process; (b) solicitations should be open to all sources to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity; (c) solicitations conducted at regular intervals; (d) oversight by an independent administrator; and (e) certification as fulfilling the above criteria by the state regulatory authority or nonregulated electric utility.[56]

APPA and LPPC generally endorse this approach. LPPC members, for example, have administered competitive solicitations and have found them worthwhile, eliciting valuable, competitive projects that provide clear price signals of the value of alternative energy and capacity.

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[55] NOPR at P 71.

[56] NOPR at P 87 (footnote omitted). *See also*, proposed § 292.304(b)(8).

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With that said, APPA and LPPC ask for certain limited modifications of the stated criteria the Commission has outlined for competitive solicitation. First, the proposed criterion specifying that solicitations be conducted at regular intervals should be modified or clarified. If solicitations are held at regular intervals, APPA and LPPC agree they should certainly satisfy PURPA's purchase obligation. But this should not be a requirement. If solicitations are not held at regular intervals, the utility will maintain a purchase obligation under PURPA.[57] However, APPA and LPPC believe that for some commercially reasonable time following the solicitation, it should be permissible to use the results of the competitive solicitation as a measure of avoided costs, since this data serves as the best available evidence of alternative pricing.

Second, APPA and LPPC do not see the need for oversight of the solicitation process by an independent administrator. The entire PURPA administrative construct is designed to entrust to State Regulatory Authorities the responsibility to carry out the duties they are assigned under the Commission's regulations.[58] This is an essential feature of the framework for cooperative federalism envisioned under the statute, and the proposed addition to the options specifically available to State Regulatory Authorities under section 292.304(b)(8) should be no different. Indeed, the Commission in Order No. 69 was explicit in stating that its rules implementing PURPA afford State Regulatory Authorities "great latitude in determining the manner of implementation of the Commission's rules, provided that the manner chosen is reasonably designed to implement the requirements of Subpart C" of those regulations.[59] The Commission further declined to adopt overly prescriptive rules applicable to State Regulatory Authorities in

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[57] *See Hydrodynamics*, 146 FERC ¶ 61,193 (2013).

[58] Section 210(f) of the Act expressly calls for State regulatory authorities and nonregulated electric utilities to implement FERC regulations. 16 U.S.C. § 824a-3(f).

[59] Order No. 69 at 30,891-92.

Order No. 69, instead voicing its belief that "providing an opportunity for experimentation by the States is more conducive to development of these difficult rate principles."[60] Over the ensuing years since Order No. 69 was issued, the Commission has continued to give State Regulatory Authorities wide latitude in implementing PURPA, due in part to FERC's "recognition of the important role which Congress intended to give [State Regulatory Authorities] under PURPA."[61] Should State Regulatory Authorities fail to implement the Commission's PURPA regulations, or should they misstep in doing so, the enforcement machinery under the statue is available to complainants.[62]

B. Any Final Rule Should Clarify the Treatment of All-Requirements Customers

In any final rule implementing the proposed revisions to the Commission's regulations relating to avoided costs, APPA and LPPC respectfully request that the Commission ensure clarity on a point of particular relevance to public power utilities. Specifically, the Commission should confirm that an all-requirements customer may use the avoided cost methods adopted in the final rule when calculating the avoided costs of its all-requirements supplier to determine its avoided cost rates, consistent with longstanding Commission precedent.[63] While APPA and LPPC assume that this is the Commission's intent given the absence of any suggestion in the NOPR that the Commission proposes to depart from its longstanding policy on the issue,

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[60] Order No. 69 at 30,892.

[61] *So. Cal. Edison*, 70 FERC ¶61,215, at 61,675 (1995); see *American REF-FUEL Co. of Hempstead*, 47 FERC ¶61,161, at p. 61,533 (1989) (State Regulatory Authorities "are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with our regulations.); *see LG&E-Westmoreland Hopewell*, 62 FERC ¶61,098, at p. 61,712(1993) ("States are allowed a wide degree of latitude in establishing an implementation plan under PURPA.").

[62] *See* 16 U.S.C. § 824a-3(g) and (h) (judicial review and enforcement; and Commission enforcement).

[63] *See, e.g., Basin Elec. Power Coop.,* 160 FERC ¶ 61,078, P 16 n.18 (2017) (citing precedent).

numerous public power electric utilities take full requirements service from joint action agencies and similar entities, and confirmation of this point would help avoid ambiguity concerning application of the final rule to public power load serving entities.

C. Relief from Purchase Obligation in Competitive Retail Markets (NOPR, PP 89-92)

The Commission proposes to modify section 292.303(a) (which requires electric utilities generally to purchase "any energy and capacity which is made available from a qualifying facility") to relieve utilities from this purchase obligation to the extent their supply obligations are reduced by a state's retail choice program.

APPA and LPPC support this change. It is sensible that where a utility's supply obligation has been reduced as a result of retail competition through a state retail choice program, that the utility's purchase obligation similarly may be reduced. APPA and LPPC agree with the Commission that this change will provide State Regulatory Authorities with the flexibility they need to respond to circumstances where a utility's supply obligation may decrease over time due to retail choice.[64]

D. Evaluation of Whether QFs are Separate Facilities (NOPR, PP 93-118)

1. Rebuttable Presumption of Separate Facilities (NOPR, PP 100-107)

The Commission proposes to revise its current "one-mile rule" for determining whether generation facilities should be considered to be part of a single facility for purposes of determining qualification as a qualifying small power production facility.[65] Specifically, the Commission proposes to allow entities challenging a QF certification to rebut the current presumption that affiliated facilities located more than one mile apart are considered to be

[64] NOPR at P 92.

[65] NOPR at PP 100-07.

separate QFs. Such entities may demonstrate that affiliated facilities located between one and ten miles apart (*i.e.*, more than one mile apart and less than ten miles apart) are a single facility. The Commission identifies a series of physical and ownership factors which may be asserted to rebut or defend against rebuttal, noting however that "no single factor would be dispositive."[66] The NOPR further provides that affiliated facilities with distances of one mile or less "are currently and will continue to be irrebuttably presumed to be a single facility at a single site," while affiliated facilities that are ten miles or more apart "will be irrebuttably presumed to be separate facilities at separate sites."[67]

APPA and LPPC support the Commission's proposal to revise the rebuttable presumption of separate facilities, which seems sensible to prevent instances where affiliated small power production facilities that use the same energy resource may be strategically sited slightly more than one mile apart so as to circumvent the "one-mile rule" in the Commission's regulations, and in so doing circumvent PURPA's 80 MW threshold for small power production facilities. APPA and LPPC agree that there is reasonable concern that the existing "one-mile rule" articulated at 18 C.F.R. § 292.204(a) of FERC's regulations implementing PURPA is vulnerable to manipulation in this manner by some QF developers.[68] The Commission's approach to addressing this problem is logical and sufficiently tailored in that it retains a presumption that affiliated facilities located more than one mile apart are considered to be separate QFs, but permits entities challenging a QF certification to rebut that presumption.

APPA and LPPC further believe the physical and ownership factors enumerated by the Commission are sensibly tailored to ascertain important attributes of a project, including

[66] NOPR at P 105.

[67] NOPR at P 101.

[68] NOPR at P 97.

information pertaining to its ownership, control and affiliated entities, to help ensure that the rebuttable presumption functions as intended.

2. Proposed Definition of "Electrical Generating Equipment" (NOPR, PP 108-110)

The Commission also proposes to define the term "electrical generating equipment" in its regulations implementing PURPA.[69] The Commission observes that section 292.204(a)(2)(ii) states that to measure one mile, "the distance between facilities shall be measured from the electrical generating equipment of a facility" but, it adds, the PURPA regulations "do not define what constitutes electrical generating equipment or explain how to measure the distance between facilities."[70] To address this issue, the Commission proposes amending 18 C.F.R. § 292.202 to include a definition of "electrical generating equipment."[71] Specifically, the NOPR proposes defining "electrical generating equipment" to refer to all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar panels and/or inverters, fuel cell equipment and/or other primary power generation equipment used in the facility, excluding equipment for gathering energy to be used in the facility.[72] With respect to wind turbines and solar panels, the Commission notes its expectation that "each wind turbine on a wind farm and each solar panel in a solar facility would be considered 'electrical generating equipment' because each wind turbine and each solar panel is independently capable of producing electric energy."[73]

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[69] NOPR at PP 108-09.

[70] NOPR at P 93.

[71] NOPR at PP 94, 98-99.

[72] NOPR at P 108.

[73] NOPR at P 108.

The Commission further proposes measuring the distance between the nearest "electrical generating equipment" of any two facilities such that, for the facilities to be considered irrebuttably separate, "all such equipment of one QF must be at least ten miles away from all such equipment of another QF."[74]

APPA and LPPC support the definition of "electrical generating equipment" as proposed in the NOPR, and further support the Commission's proposed approach for specifying how to measure the distance between facilities that have multiple sets of "electric generating equipment." APPA and LPPC believe FERC's proposal to be a reasonable approach, providing useful clarity to its existing regulations.

3. Corresponding Changes to FERC Form No. 556 (NOPR, PP 111-117)

The NOPR proposes revisions to FERC Form No. 556 to add a new item 8b, which would be similar to the current item 8a, but would cover affiliated facilities whose nearest electrical generating equipment is greater than one mile and less than 10 miles from the electrical generating equipment of the instant facility.[75] The Commission further proposes that the instructions for the new item 8b would allow applicants with facilities that are more than one mile apart and less than ten miles apart to explain why these facilities identified under item 8b should be deemed separate facilities, taking into account the relevant physical and ownership factors considered by the Commission.[76]

APPA and LPPC support the NOPR proposal to revise FERC Form No. 556 to include a new item 8b. The new item would provide clarity to interested parties regarding the nature of an applicant's facilities, and potentially the appropriateness of applying to such facilities the

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[74] NOPR at P 109.

[75] NOPR at P 112.

[76] NOPR at P 113.

Commission's presumption that facilities which are more than one mile apart and less than ten miles apart should be considered separate facilities. Allowing an applicant to explain why its facilities identified under item 8b should be deemed separate facilities, considering the relevant physical and ownership factors, is likely to provide affected parties with important information upfront, and thus allow such parties to make an informed decision as to whether a challenge to the Commission's rebuttable presumption is warranted.

D. PURPA Section 210(m) Rebuttable Presumption of Nondiscriminatory Access to Markets (NOPR, PP 118-133)

The NOPR proposes to amend section 292.309(d)(1) to reduce from 20 MW to 1 MW the threshold size of QFs that the Commission will presume have nondiscriminatory access to markets typically described as Day-2 or Day-1 organized markets or their equivalent.[77] Where such access exists, PURPA section 210(m)(1) allows electric utilities to be relieved of their purchase obligation under the statute. The Commission seeks comment on its proposed threshold reduction in the size of facilities that will be presumed to have market access. It seeks further comment on factors that may be useful in making determinations under PURPA section 210(m)(1)(C)[78] that conditions outside RTOs/ISO offer "comparable competitive quality."[79]

1. Reduction from 20 MW to 1 MW in Size of QF Small Power Production Facilities to Qualify for PURPA Section 210(m) Exemption (NOPR, PP 126-130)

APPA and LPPC support the Commission's proposal to reduce from 20 MW to 1 MW the size at which FERC's rebuttable presumption attaches for small power production facilities

[77] NOPR at PP 118-133. The 20 MW threshold was established initially in Order No. 688. *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, 117 FERC ¶ 61,078 (2006), *order on reh'g*, Order No. 688-A, 119 FERC ¶ 61,305 (2007), *aff'd sub nom. Am. Forest & Paper Ass'n v. FERC*, 550 F.3d 1179 (D.C. Cir. 2008).

[78] 16 U.S.C. § 824a-3(m)(1)(C).

[79] NOPR at PP 132-33.

under section 292.309(d) of the PURPA regulations. The Commission explains that when it issued Order No. 688 the organized electric markets had been in existence for only a few years, and "were not well understood by all market participants."[80] The Commission further says that "it is fair to expect that small power production facilities above 1 MW can acquire the administrative and technical expertise necessary to obtain nondiscriminatory access to a market."[81] And finally, the Commission notes that new Fast-Track interconnection procedures implemented in 2013, and its recent decision to mandate that RTOs/ISOs implement electric storage participation models for facilities as small as 100 kW, facilitate access to organized markets for small QFs.[82]

APPA and LPPC support the Commission's proposal to reduce its rebuttable presumption threshold from 20 MW to 1 MW under section 292.309(d). As explained in Order No. 688, and repeated in the NOPR, there is no magic or "unique" megawatt size for determining when a generator is small.[83] Nor is there a clear nexus between the size of the facility and the presumption that it lacks access to Commission-regulated markets. In any event, a 1 MW facility is not tiny; a resource of that capacity exceeds by 200 times the size of an average residential solar rooftop facility,[84] and can require a substantial capital commitment.[85] And as the

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[80] NOPR at P 126.

[81] NOPR at P 127.

[82] NOPR at P 129.

[83] NOPR at P 128, citing Order No. 688-A at P 97.

[84] Solar Energy Industries Association, Solar Photovoltaic Technology, available at: https://www.seia.org/research-resources/solar-photovoltaic-technology (according to SEIA data, the average size of a residential PV system in the U.S. is 5 kW). *See also Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility*, Order No. 732, 130 FERC ¶ 61,214, at P 35 (2010) (noting that "[f]acilities larger than 1 MW . . . represent a significant departure from the smallest generation (residential, retail, hospitals, schools, etc.)").

[85] *See* Order No. 732, 130 FERC ¶ 61,214, at P 35 (observing that facilities larger than 1 MW "typically require a significant capital outlay, on the order of hundreds of thousands or millions of dollars").

Commission is well-aware based on its experience with aggregated bids into organized markets by distribution-level demand response providers,[86] quite capable of organizing through coordinated activity the necessary intellectual infrastructure to navigate RTO/ISO market participation. There is no basis, accordingly, for the assumption that the size of these facilities is administratively disabling.

2. Reliance on RFPs and Liquid Market Hubs to Terminate Purchase Obligation (NOPR, PP 131-133)

APPA and LPPC support vigorously the Commission's inquiry into factors relevant to determining when a market is of comparable competitive quality to markets described in PURPA sections 210(m)(1)(A) and (B). While the Commission accurately notes that current regulations permit electric utilities to demonstrate that a particular market is of comparable competitive quality to markets described in PURPA sections 210(m)(1)(A) and (B), the regulations do not specify applicable criteria,[87] leaving a gap that APPA and LPPC urge the Commission to fill, whether through regulations or in precedent.

APPA and LPPC members' successful experience in trading energy products at several of the hubs located throughout the nation is the focus of their thinking in this matter, raising the question whether one or more of them may serve as a platform for exemption from the purchase criteria under PURPA subsection 210(m)(1)(C). This subsection of the statute provides an opportunity to argue that even if market hubs do not meet the express criteria for exemption under subsections (A) and (B) of the provision, they may nonetheless be of "comparable

[86] *See Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶61,187 (2011), *order on reh'g and clarif.*, Order No. 745-A, 137 FERC ¶61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760 (2016).

[87] NOPR at P 132. The Commission notes that "nothing in the PURPA regulations or precedent would bar an electric utility from arguing that RFPs in combination with liquid market hubs are sufficient to satisfy PURPA section 210(m)(1)(C)." *Id.*

competitive quality." The most obvious comparison would be to subsection (B), providing that the exemption is available if the Commission finds that QFs have available to them "transmission and interconnection service…provided by a Commission-approved transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales…"[88]

Precedent in this area is quite limited and may bear revisiting. In *Public Service of New Mexico*, 140 FERC ¶ 61,191 (2012) (*"PSNM"*) the Commission rejected PSMN's application for a determination that the Four Corners hub was comparable under 210(m)(1)(C) to subsection (B) of the statute. The decision rests principally on the ground that a Commission-approved regional transmission entity did not in that case provide transmission service. The Commission further held that the Four Corners hub did not offer service to a "territory-wide market."[89] Yet, the first of these grounds (the absence of a FERC-approved regional transmission entity) is hard to square with the structure of the statute. PURPA section 210(m)(1)(C) specifies only that QFs must have access to transmission services and wholesale markets "of comparable competitive quality" to those specified in subsection 210(m)(1)(B), not the very same thing. The further holding that the Four Corners hub failed to extend to the entirety of the utility's service territory seems not to address whether the hub nonetheless offered QFs viable sales options.

With this said, parties seeking to terminate the mandatory purchase obligation pursuant to section 210(m)(1)(C) exemption are left with little guidance. To assist, APPA and LPPC

[88] 16 U.S.C. § 824a-3(m)(1)(B).

[89] *PSNM* at PP 34-35.

suggest, first, that comparability for the transmission prong of the (1)(B) analysis may be established by a showing that QFs seeking to sell into an identified hub have unfettered use of needed open access service that would limit access by suppliers to the market hub.

As to the nature of the hub itself, economic theory defining a competitive market structure and Commission precedent suggest three key factors: (1) adequate market liquidity in the relevant products; (2) market transparency; and (3) reliable contractual standards identifying the traded products and standards for delivery, receipt and settlement.

The Commission addressed the first of these factors at least twice, holding the Mid-Columbia and Palo Verde hubs to be sufficiently robust to support a finding of just and reasonable rates. The Commission makes express mention in the NOPR to these decisions in the Mid-Columbia and Palo Verde matters, referring to them as "liquid markets" representing "competitive market prices."[90] This precedent may be supplemented with an empirical test measuring market liquidity, the contour of which may be spelled out in a section 210(m) filing. It is also worth pointing out that measures of market liquidity may reflect products traded on electronic platforms such as ICE as well as products traded bilaterally in the same region.

As to price transparency, APPA and LPPC note that the opportunity for price discovery is certainly a hallmark of a working market, and a key feature of the Commission's organized markets. A showing regarding the availability of price data in published daily indices (*e.g.*, Dow Jones Electricity Price Index; Megawatt Daily) would satisfy this criterion, as may the use of electronic trading platforms such as the Intercontinental Exchange (ICE).

[90] NOPR at P 52 and n.88 (citing *Price Discovery in Natural Gas and Electric Markets*, 109 FERC ¶ 61,184, at P 66 (2004); *El Paso Electric Co.*, 148 FERC ¶ 61, 051, at P 7 (2014); *Idaho Power Co.*, 121 FERC ¶ 61,181 at P 27 (2007); *PacifiCorp*, 95 FERC ¶ 61,463, at 61,463 (2001); *Pinnacle West Energy Corp.*, 92 FERC ¶ 61,248, at 61,791 (2000)).

The third of these factors – reliable contractual standards – is the key to identifying the relevant traded products and ensuring their fungibility for purposes of evaluating the viability of the market. Contractual terms may be identified on relevant electronic trading platforms,[91] and they may be identified in bilateral agreements.

APPA and LPPC take note of the effort undertaken by the National Association of Regulatory Utility Commissioners ("NARUC") (cited by the Commission at NOPR P 131) to advance supply procurement RFPs as a means of satisfying PURPA section 210(m)(1)(C).[92] The genesis for this thinking appears to lie in the discussion in Order No. 688 suggesting that an open product procurement framework may create the predicate for a market.[93] APPA and LPPC are certainly willing to entertain this idea, but ask that it be considered as an effort to create markets (or perhaps market surrogates) where none exist.

E. Legally Enforceable Obligation (NOPR, PP 134-142)

The Commission proposes to add regulatory text at 18 C.F.R. § 292.304(d)(3) requiring QFs "to demonstrate commercial viability and a financial commitment to construct its facility pursuant to criteria determined by the state regulatory authority or nonregulated electric utility as a prerequisite to …obtaining a legally enforceable obligation."[94] The proposed regulation further says that such criteria must be objective and reasonable, while the Commission adds that states have flexibility in setting criteria to meet the new requirements.

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[91] *See, e.g.*, ICE indices reported here, for trades at Palo Verde: https://www.theice.com/site-search?q=palo%20verde

[92] *See* NARUC Supplemental Comments, Docket No. AD16-16-000, at Attachment A, *Aligning PURPA with the Modern Energy Landscape: A Proposal to FERC* (filed Oct. 17, 2018).

[93] *See* Order No. 688 at P 139.

[94] NOPR at P 140 and proposed 18 C.F.R. § 292.304(d)(3).

APPA and LPPC support the Commission's proposed revision. While the Commission has been clear that State Regulatory Authorities are invested with considerable (but not unbounded) discretion in determining the prerequisites for creation of a LEO, the proposed addendum to the regulations establishes a baseline for what a QF must demonstrate that will be useful. This will help ensure that a purchasing utility's obligations under PURPA are not triggered for QF projects that are insufficiently advanced in their development. APPA and LPPC agree with the Commission that requiring such a demonstration will allow utilities to reliably plan for their systems, thus ensuring resource adequacy, and will further ensure that QF projects that cannot meet a showing of commercial viability based on such criteria are not included in a utility's resource planning. PURPA's must purchase obligation can also impact utilities' long-term generation capacity planning when they are unexpectedly required to purchase power not accounted for in an integrated resource plan. This can be especially challenging for smaller public power entities. APPA and LPPC believe that the Commission's proposed reforms concerning when a LEO is established help utilities and their customers manage this uncertainty as they develop resource planning assumptions and undertake the process of reliably planning their systems. By the same token, establishing objective and reasonable factors will also provide QFs with increased certainty as to when they will obtain a LEO.

APPA and LPPC further believe it is appropriate to provide State Regulatory Authorities flexibility in determining what constitutes an acceptable showing of commercial viability and financial commitment with respect to QF projects, as the Commission contemplates.[95] Such flexibility is vital to ensure that State Regulatory Authorities may develop criteria that reflect their unique operational circumstances, resource planning needs and horizon, and risk appetite.

[95] NOPR at P 140.

In exercising that discretion, the indicia the Commission identifies at NOPR P 141 are a sensible starting point for the development and definition of objective, reasonable factors to determine a QF's commercial viability and financial commitment to construct a facility. APPA and LPPC particularly support the Commission's references to: (1) a demonstration of adequate site control enabling the QF to commence construction; (2) filing an interconnection application; and (3) secured local permitting and zoning of the project. Among other things, these are essential requisites for a project to demonstrate commercial viability.

F. QF Certification Process - The Commission Should Adopt the Proposal to Reform the QF Self-Certification Process (NOPR, PP 143-152)

With the exception of filings from certain cogeneration facilities, the Commission currently does not publish notices of QF self-certifications, nor does the Commission consider protests of interested parties in self-certification dockets.[96] A party seeking to challenge the eligibility of a self-certified QF is obligated instead to file a petition for declaratory order under Commission Rule 207, along with the requisite filing fee.[97] In the NOPR, the Commission proposes to modify this framework to allow interested parties to intervene in QF self-certification dockets and file protests challenging QF certification.[98] The Commission states that a party filing such a protest "would have the burden of specifying facts that make a prima facie demonstration that the facility described in the self-certification or self-recertification does not satisfy the requirements for QF status,"[99] at which point the burden would shift to the party filing

[96] *See* NOPR at PP 143-45; 18 C.F.R. § 292.207(c) (2019). The Commission has noted that "recertification is a type of certification," Order No. 732, 130 FERC ¶ 61,214, at P 7 n.10, and references in these comments to certification should be read to include recertification.

[97] *See* NOPR at P 146; 18 C.F.R. § 385.207 (2019).

[98] NOPR at P 148.

[99] NOPR at P 149.

the self-certification to rebut the challenger's claims and show that certification is warranted.[100] APPA and LPPC support the Commission's proposed reforms to the QF self-certification process.

For facilities that choose to self-certify, the Form No. 556 filing requirement is a prerequisite for QF status.[101] The Form No. 556 submission initially functioned only as an informational filing, but since the issuance of Order No. 671 in 2006, it has been "a substantive and important criterion for QF status . . . ."[102] The Commission's decision to adopt a certification filing as a formal requirement of QF status was based, in large measure, on the fact "that EPAct 2005 call[ed] for greater Commission scrutiny of QF status," particularly cogeneration facilities.[103] And while Commission Staff does not ordinarily review self-certification filings to assess whether the applicant otherwise satisfies the QF criteria,[104] "the Commission has the authority to review and question a self-certification."[105] Indeed, the Commission has previously launched investigations of QF eligibility based on review of QF files in response to concerns "that some facilities may have, at times, used the self-certification procedures to avoid a thorough examination of whether a facility satisfies the criteria for QF status."[106] Thus the self-certification filings play an important role in monitoring whether particular QF applicants otherwise satisfy applicable eligibility requirements.

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[100] NOPR at P 149.

[101] *See* NOPR at P 145; *see also* 18 C.F.R. § 292.203 (2019); *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671, 114 FERC ¶ 61,102, at P 82 (2006), *order on reh'g*, Order No. 671-A, 115 FERC ¶ 61,225 (2006). As discussed below, QFs with a net power production capacity of 1 MW or less are exempt from the Commission's certification requirements. 18 C.F.R. § 292.203(d) (2019).

[102] *Rockville Solar I LLC*, 168 FERC ¶ 61,075, at P 9 (internal quotes and citations omitted).

[103] Order No. 671 at P 79; *see also id.* at PP 82-83.

[104] NOPR at P 143.

[105] Order No. 671 at P 78.

[106] *Investigation of Certain Enron-Affiliated QFs*, 103 FERC ¶ 61,122, at P 13 (2003).

Given the important notice and monitoring function played by Form No. 556 submissions, it is reasonable and appropriate for the Commission to consider information in a protest of a QF's eligibility when a Form No. 556 filing is submitted, rather than requiring an interested party to initiate a separate declaratory order proceeding. Even leaving aside the significant fee required to file a petition for declaratory order (currently $28,990),[107] the need to initiate an entirely new declaratory proceeding, and shoulder the burden to show that a self-certification should be revoked, is likely to deter parties from bringing relevant information about questionable QFs to the Commission's attention. An interested party may also be discouraged from filing a petition for declaratory order by lack of access to complete information about a putative QF, even in a case where the party may have enough information to call the facility's eligibility into question. The filing requirement is "a substantive and important criterion for QF status,"[108] and facilities filing self-certifications should have the burden of justifying their QF status against legitimate objections at the time the self-certifications are submitted.

APPA and LPPC acknowledge the Commission's longstanding concern "that the complexity, delays, and uncertainties created by a case-by-case qualification procedure would act as an economic disincentive to owners of smaller facilities."[109] The NOPR, however, strikes an appropriate balance between the regulatory burdens placed on QFs and the ability of interested parties to raise valid QF eligibility concerns in an efficient manner. It is important to emphasize in this regard that the NOPR does not propose to eliminate the current certification

[107] APPA and LPPC note that states and municipalities can claim an exemption from this and other Commission fees. *See* 18 C.F.R. § 381.108 (2019).

[108] *Rockville Solar I LLC*, 168 FERC ¶ 61,075, at P 9 (2019) (internal quotes and citations omitted).

[109] Order No. 671 at P 83.

filing exemption for QFs with a net power production capacity of 1 MW or less[110] and, thus, these smaller facilities would not face any additional administrative complexities if the proposed rule were adopted. The framework proposed in the NOPR should not represent an undue burden for the larger facilities that would be subject to the new rule. As the Commission observed in retaining the certification filing requirement for larger QFs, "[f]acilities larger than 1 MW . . . represent a significant departure from the smallest generation (residential, retail, hospitals, schools, etc.)" [111] Such facilities, the Commission explained, "typically require a significant capital outlay, on the order of hundreds of thousands or millions of dollars, and the additional burden, both financial and otherwise, of filing with the Commission will be comparatively minimal."[112] Facilities of this size and cost – including cogeneration facilities – likewise should be able to manage any additional burden associated with allowing interventions and protests of their self-certification filings. And the greater impact that such QFs can have on electric utilities in terms of cost and planning impacts further justifies the opportunity for more robust eligibility review at the Form No. 556 filing stage.

The proposed rules would also continue to accommodate QF self-certification by making self-certification effective upon the filing of Form No. 556 and requiring protesting parties to specify facts sufficient to make a prima facie demonstration that the facility does not meet the applicable QF requirements.[113] Placing this initial burden of production on challengers should avoid unjustified objections to QF certifications, while appropriately leaving the ultimate burden

[110] 18 C.F.R. § 292.203(d) (2019).

[111] Order No. 732 at P 35.

[112] *Id.*

[113] NOPR at P 149.

of persuasion on QFs when protesting parties offer prima facie evidence that a facility does not qualify as a QF.[114]

For these reasons, APPA and LPPC urge the Commission to adopt the changes to the QF self-certification process proposed in the NOPR.

IV. CONCLUSION

For the foregoing reasons, APPA and LPPC ask the Commission to issue any Final Rule in these proceedings consistent with the comments articulated herein.

Respectfully submitted,

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December 3, 2019

[114] *Cf.* 5 U.S.C. § 556(d) ("[e]xcept as otherwise provided by statute, the proponent of a rule or order has the burden of proof.").