Divided FERC Revamps PURPA Regulations: What the Final Rule Does and Why It Matters

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The changes will have meaningful effects on developers and owners of and investors in such energy projects, known as "qualifying facilities" (QFs). The Final Rule generally adopts changes FERC proposed in September 2019,[3] which we addressed here, with some important adjustments discussed below. House Energy and Commerce Committee Chairman Frank Pallone Jr. (D-NJ) and Energy Subcommittee Chairman Bobby L. Rush (D-IL) condemned FERC's action, and suggested they will continue working on federal legislation that would counteract certain aspects of the Final Rule.[4]

In our view, the changes to FERC's regulations likely will reduce opportunities for development of certain renewable energy resources in certain markets, especially in some western and southeastern states. Preservation of the status quo in some areas of FERC's regulations will be helpful, but may be cold comfort to developers and owners of and investors in QFs, some of whom will feel the changes in profound ways. But, however significant the overall effect of the Final Rule, its implementation will require adjustments to project development approaches, legal due diligence processes and regulatory compliance plans.

Overview

The Final Rule focuses on three areas of PURPA: (1) the "avoided cost"[5] cap on QF rates; (2) the 80 MW limit on the combined generating capacity of affiliated small power production QFs "located at the same site" (and how being "located at the same site" is determined); and (3) termination of the mandatory purchase obligation for QFs with nondiscriminatory access to certain markets.[6] In sum, FERC:

- Increased flexibility for states to set "avoided cost" rates for QF energy inside and outside of organized markets (i.e., markets administered by Independent System Operators/Regional Transmission Organizations (ISOs/RTOs)), including requiring that energy rates (but **not** capacity rates) vary over the term of a QF contract according to the purchasing utility's avoided cost for as-available energy at the time of delivery.[7]
- Enabled states to choose whether "to allow QFs to have a fixed energy rate . . . based on projected energy prices during the term of a QF's contract based on the anticipated dates of delivery"[8] **or** to set as-available energy rates based on "competitive" rates such as:
  - in organized markets, locational marginal prices (LMP), with a rebuttable presumption that LMP represents the purchasing utility's avoided energy cost;[9] or
  - in other markets, prices from liquid market hubs to which the purchasing utility has reasonable access or based on natural gas price indices and heat rates, if the state first determines such prices represent the purchasing utility's avoided cost.[10]
- Allowed states to set QF energy and capacity rates using competitive solicitations (i.e., requests for proposals) conducted under certain minimum transparency and nondiscrimination procedures.[11]
- Changed when certain QFs can force utilities to purchase their output, including reducing the size of small power production (but not cogeneration) QFs rebuttably presumed to have nondiscriminatory access to markets from 20 MW to 5 MW.[12]
- Converted its formerly bright-line "one-mile rule" for determining QF size into a tiered analysis combining bright-line elements with a rebuttable presumption regarding whether certain facilities are "located at the same site."[13]
- Required QFs to show commercial viability and financial commitment to build under objective, reasonable state-determined criteria before becoming entitled to a contract or legally enforceable obligation (LEO) for a utility to purchase its output.[14]
- Opened the QF certification processes to protests under certain circumstances, and eliminating the need for challengers to file and pay for a declaratory order.[15]

Importantly, FERC retained various aspects of its existing PURPA regulations intended to encourage QF development, such as continuing to require QF rates be set at full avoided cost; requiring utilities to provide backup power to QFs on a nondiscriminatory basis and at just and reasonable rates; requiring utilities to interconnect with QFs; and providing regulatory relief through exemptions for certain QFs from certain provisions of the Federal Power Act (FPA), the Public Utility Holding Company Act of 2005 (PUHCA), and certain state laws and regulations governing utility rates and financial organization.[16]

The Final Rule will become effective 120 days after publication in the Federal Register, and FERC emphasized that the changes "are effective prospectively for new contracts or LEOs and for new facility certifications and recertifications filed on or after the effective date" of the Final Rule—i.e., they "do not . . . permit disturbance of existing contracts or LEOs or existing facility certifications."[17]

For brief background on PURPA and the NOPR, please see our earlier post here.

What Did FERC Do? – Summary of Reforms Adopted in the Final Rule

1. Expansion of State Flexibility in Determining QF Energy Rates

PURPA requires FERC to promulgate rules, to be implemented by states, establishing the rates utilities pay for purchases of QF energy. FERC's current regulations give QFs the option to: (1) provide "as-available" energy at a rate based on the utility's "avoided cost" at the time of delivery (the "as-available option"); or (2) provide energy pursuant to a LEO, over a specified term, at a rate based on avoided cost at delivery or when the obligation was incurred (the "contract option").[18]

The NOPR proposed to allow states to "incorporate competitive market forces in setting QF rates,"[19] and the Final Rule significantly expanded state discretion in setting PURPA rates, finding that "use of transparent, competitive market prices provides encouragement to QFs, represents the avoided cost, and can ensure that the rate does not exceed the incremental cost to the purchasing electric utility."[20] This change manifests in three primary ways:

- First, because long-term fixed avoided cost energy rates may exceed the purchasing utility's avoided cost for energy, FERC granted states "flexibility to require that energy rates (but **not** capacity rates) in QF power sales contracts and other LEOs vary in accordance with changes in the purchasing electric utility's as-available avoided costs at the time the energy is delivered."[21] If a state "exercises this flexibility, a QF no longer would have the ability to elect to have its energy rate be fixed, but would continue to be entitled to a fixed capacity rate for the term of the contract or LEO."[22]

- Second, FERC granted states "flexibility to allow QFs to have a fixed energy rate, but to provide that such state-authorized fixed energy rate can be based on projected energy prices during the term of a QF's contract based on the anticipated dates of delivery."[23]
- Third, FERC granted states flexibility to set "as-available" QF energy rates as follows: (1) in RTO/ISO markets, at the applicable LMP, with a rebuttable presumption that LMP is the as-available avoided cost of energy for utilities in those markets;[24] and (2) outside of RTO/ISO markets, "at competitive prices from liquid market hubs or calculated from a formula based on natural gas price indices and specified heat rates, provided that the states first determine that such prices represent the purchasing electric utilities' avoided costs."[25]

Importantly, states "have the flexibility to choose to adopt one or more of these options" or to continue setting QF rates using the long-established approaches described above.[26] These changes, FERC asserts, allow states to "better ensure that QF rates are at, but do not exceed, the statutory maximum [avoided cost] rate established by Congress."[27] The Final Rule "adds factors that must be taken into account to the extent practicable in setting rates, while retaining the 'great latitude' the states always have had to implement the PURPA Regulations."[28]

FERC also allowed states to set QF energy **and** capacity rates using "properly structured" competitive solicitations with certain minimum features, including: (1) an open and transparent process; (2) availability to "all sources to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity;" (3) solicitations be conducted at regular intervals; (4) "oversight by an independent administrator;" and (5) certification that the process meets the criteria by the state regulatory authority or nonregulated electric utility.[29]

In addition, FERC proposed in the NOPR to allow "fixed energy rates to be based on forecasted estimates of the stream of revenue flows during the term of the contract," based on "forecasts . . . available for LMPs in RTOs/ISOs, for liquid market hubs located outside of

RTOs/ISOs, and for natural gas pricing hubs" when such estimates reflect avoided costs.[30] In the Final Rule, FERC adopted this proposal, noting that it "previously permitted the use of this method to establish energy and capacity rates over the term of a contract or LEO," and clarifying that "a state may use competitive market prices and/or variable energy rates in the context of a more fixed estimated avoided cost energy rate (together with a fixed avoided capacity rate) that is determined at the time an LEO or contract is incurred."[31] Such fixed energy rate "could be a single rate, based on the amortized present value of forecast energy prices, or it could be a series of specified rates that change from year-to-year (or other periods) in future years."[32] FERC also will allow states to "establish the applicable energy rate(s) for the QF for the entire term or the rate may change from year-to-year (or some other period) of the contract at the time the LEO is incurred."[33]

While these changes might reduce utility (and consumer) costs for QF energy where avoided costs are less than long-term fixed contract rates for QFs, variable energy rates could potentially reduce the availability of financing for certain QFs. The majority voting for the Final Rule disagrees, noting that, "[n]otwithstanding that PURPA does not guarantee QF financeability, the Commission believes that the variable avoided cost energy rate option . . . will still allow QFs to obtain financing."[34] Indeed, it "may promote longer contract terms, which would help encourage and support QFs,"[35] and the "combination of fixed avoided cost capacity rates and variable energy rates can provide important revenue streams that can support the financing of QFs."[36] The effect of the Final Rule on the financeability of QFs may vary state by state, as it will be highly contingent on each state's existing policies and implementation of the new regulations. For example, certain states had already shortened the standard QF fixed-rate contract to just a few years due to uncertainty regarding future avoided posts. In such states, pivoting away from the fixed-rate option and adoption of more flexible, as-available avoided costs may increase the financeability of QFs. However, the impact may be less positive in other states that currently have more generous PURPA policies if they decide to depart from the fixed-rate option.

FERC did not completely eliminate fixed rates for QFs.[37] Rather, it "gave states the flexibility . . . to require that the avoided cost **energy** rates in QF contracts must vary depending on avoided costs at the time of delivery (rather than being fixed at the time a LEO is incurred)."[38] FERC retained "the option granted to QFs to fix their **capacity** rates for the term of their contracts at the time the LEO is incurred."[39] This should mitigate some of the adverse effects on financing that could have resulted from full elimination of fixed-rate pricing for QFs. In addition, pivoting from the proposal in the NOPR to allow LMP as a per se representation of avoided cost in organized markets to a rebuttable presumption will enable concerned QF developers and owners more opportunities to challenge such determinations.[40] It is reasonable to expect an increase in this type of litigation.

2. Conversion of the Bright-Line "One-Mile Rule" to a Tiered Analysis for Determining Whether Facilities Are "Located at the Same Site"

Under FERC's current regulations, the maximum net power production capacity of a small power production facility, "together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site," cannot exceed 80 MW.[41] For nonhydroelectric small power production facilities, FERC considers a facility to be "located at the same site" as another facility if any part of the "electrical generating equipment" of one facility (not currently defined in the regulations) was within one mile of any part of the "electrical generating equipment" of the other facility.[42] This is commonly known as the "one-mile rule"—which FERC has repeatedly held to be a bright-line rule, not a rebuttable presumption[43]—and determines whether a facility is eligible for small power production QF status, as well as for certain legal and regulatory exemptions attached to small power production QF status.

In the Final Rule, FERC pivoted from the existing bright-line test to a three-tiered analysis:

- "[I]f a small power production facility seeking QF status is located one mile or less from any affiliated small power production QFs that use the same energy resource, it will be irrebuttably presumed to be at the same site as those affiliated small power production QFs."
- "If a small power production facility seeking QF status is located ten miles or more from any affiliated small power production QFs that use the same energy resource, it will be irrebuttably presumed to be at a separate site from those affiliated small power production QFs;" and
- "If a small power production facility seeking QF status is located more than one mile but less than ten miles from any affiliated small power production QFs that use the

same energy resource, it will be rebuttably presumed to be at a separate site from those affiliated small power production QFs."[44]

Thus, the Final Rule "retains the presumption that small power production QFs more than one mile apart are located at separate sites, but simply makes the presumption rebuttable for small power production QFs located more than one mile but less than 10 miles apart," allowing FERC to address challenges to the "separateness" of facilities in the middle band.[45]

Small power production facilities seeking QF status can "preemptively defend against anticipated challenges by identifying [physical and ownership] factors that affirmatively show that its facility is indeed at a separate site," and any interested party can challenge a new QF certification or recertification "that makes substantive changes to [an] existing certification."[46] (More on this below in Part 5.) Any such challenge must make a "prima facie demonstration that the facility . . . does not satisfy the requirements for QF status" and "must be adequately supported, with supporting documents, contracts, or affidavits, as appropriate."[47] In addition, as before, FERC may "waive the method of calculation of the size of [a] facility for good cause."[48] Factors relevant to the "same site" analysis include, but are not necessarily limited to:

- Physical characteristics, including common or shared infrastructure, property ownership or leases, control facilities, access or easements, interconnection agreements or facilities, collector systems or facilities, points of interconnection, motive force or fuel source, off-take arrangements, permitting or step-up transformers.
- Ownership/other characteristics, including whether facilities are owned or controlled by the same person(s) or affiliates; operated or maintained by the same or affiliated entity(ies); selling to the same utility; using common debt or equity financing; constructed by the same entity within a year; placed into service within a year of an affiliated small power production QF or sharing engineering or procurement contracts.[49]

No single factor is dispositive and FERC will analyze preemptive demonstrations and challenges case by case.[50] Importantly, FERC also held that it would continue to apply the analysis "generally to the regulations issued pursuant to PURPA," including to determinations of eligibility for the exemptions from the Form 556 filing requirement for facilities smaller than 1 MW and for certain QFs from regulation under the FPA, PUHCA, and certain state laws and regulations.[51]

FERC also added a definition of "electrical generating equipment" to clarify how the distance between facilities will be calculated.[52] Now, "electrical generating equipment" means "all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar panels, 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."[53] While there was little doubt that "electrical generating equipment" included each separate turbine in a wind facility, FERC has now made clear that the proximity analysis applies to each inverter **and** panel in a solar photovoltaic facility because each "is independently capable of producing electric energy."[54]

Making the "middle tier" of the proximity analysis into a rebuttable presumption likely will open more small power production facilities seeking QF status to challenges by utilities and others by protest, rather than petition for declaratory order. Importantly, however, such challenges could only be made to QF certifications and recertifications submitted after the effective date of the Final Rule. In addition, because FERC will continue to use the proximity analysis for making QF size determinations beyond the 80 MW maximum size determination, whether facilities are "located at the same site" remains relevant to whether certain facilities are exempt from most provisions of the FPA (including whether they require market-based rate authority from FERC), PUHCA, and certain state laws and regulations.[55] This change also will affect how renewable energy project developers—particularly those developing projects with multiple pieces of "electrical generating equipment"—perform due diligence on property selection and equipment siting when planning multiple projects, which could increase regulatory uncertainty and development costs, and could even make some projects economically unviable.

3. Reduction of the 20 MW Threshold for Termination of the Mandatory Purchase Obligation to 5 MW for Small Power Production QFs in Organized Markets

Key to PURPA is the "mandatory purchase obligation"—often called the "PURPA put"—which requires electric utilities to purchase the power produced by QFs at the utility's avoided cost. Under FERC's current regulations, QFs have the option of having the "avoided cost" rate determined at the time the QF delivers electricity to the utility or, alternatively, at the time the QF enters into a power purchase agreement (PPA) with the utility (which is often before the facility is developed). In the Energy Policy Act of 2005, Congress amended PURPA to provide for the termination of a utility's mandatory purchase obligation where QFs have nondiscriminatory access to markets that meet certain criteria. FERC subsequently created a rebuttable presumption that QFs larger than 20 MW have nondiscriminatory access to markets if they are eligible for interconnection service under a FERC-approved open access transmission tariff and interconnection rules in markets with certain characteristics. For QFs at or below 20 MW, there is currently a rebuttable presumption that the QF does not have nondiscriminatory access to markets. In such markets, utilities could terminate their obligation to purchase output from QFs larger than 20 MW, but must continue purchasing output from smaller QFs unless the utility can demonstrate that such QFs have nondiscriminatory access to transmission and a wholesale market.

In the NOPR, FERC proposed to "reduce the net power production capacity level at which the presumption of nondiscriminatory access to a market attaches for small power production facilities, but not cogeneration facilities, from 20 MW to 1 MW."[56] In the Final Rule, FERC instead reduced the presumption threshold to 5 MW, although the 20 MW threshold will remain in place for cogeneration QFs.[57]This will relieve most utilities in organized wholesale markets from the mandatory purchase obligation for QFs larger than 5 MW on the theory that such QFs have nondiscriminatory access to such markets.[58]

FERC also identified factors that a small power production QF larger than 5 MW could use to rebut the presumption that it has nondiscriminatory access to markets.[59] They include: (1) barriers to connecting to the transmission grid; (2) difficulties in interconnection request processing; (3) lack of affiliation with entities that participate in organized markets; (4) a primary purpose other than selling electricity that justifies treatment like a cogenerator; (5) operational characteristics that prevent market participation; and (6) transmission constraints.[60] FERC will consider such factors on a case-by-case basis in considering claims of lack of nondiscriminatory access to markets.[61] Importantly for utilities, those for which FERC "already granted relief from the mandatory purchase obligation for small power production facilities over 20 MW must reapply with the Commission requesting relief from the mandatory purchase obligation for small power production facilities between 5 MW and 20 MW."[62]

FERC explained that this change recognizes that competitive markets have matured since it first implemented PURPA's provisions regarding termination of the mandatory purchase obligation, "and the mechanics of participation in such markets are improved and better understood."[63] For cogeneration QFs, the 20 MW rebuttable presumption will remain because new cogeneration facilities are statutorily required to demonstrate that they are intended primarily to generate useful thermal output, rather than electricity for sale to a utility, and so might be less familiar with accessing wholesale markets.[64] FERC also affirmed that, for utilities outside of organized markets, it will "consider utility proposals to terminate the purchase obligation . . . on a case-by-case basis, including utility proposals based on competitive solicitations or liquid market hubs."[65] FERC did not establish an exhaustive list of factors for use in such evaluations, but pointed to the same criteria it will use in connection with competitive solicitations used to determine avoided cost, as discussed above.[66]

Because there are a number of small power production QFs between 5 MW and 20 MW, this change may reduce the overall number of small power production QFs able to take advantage of the mandatory purchase obligation. However, FERC's decision not to reduce the threshold all the way to the proposed 1 MW is helpful for facilities at the smaller end of the spectrum.

4. Identification of Specific Criteria for Formation of LEOs

FERC's current regulations provide that a QF, under the contract option, may choose either: (1) the purchasing utility's avoided cost calculated at the time of delivery; or (2) the purchasing utility's avoided cost calculated and fixed at the time the LEO is incurred.[67] However, the existing regulations "do not specify when or how a LEO is established."[68]

In the Final Rule, FERC held that a QF must demonstrate commercial viability and a financial commitment to construct its proposed facility pursuant to objective, reasonable, state-determined criteria to be eligible for a contract or LEO.[69] This is intended to "ensure that no electric utility obligation is triggered for those QF projects that are not sufficiently advanced in their development, and . . . would be unreasonable for a utility to include in its resource planning," while also "ensur[ing] that the purchasing utility does not unilaterally and unreasonably decide when its obligation arises."[70] However, states "may not impose any requirements for a LEO other than a showing of commercial viability and a financial commitment to construct the facility."[71]

Examples of permissible factors include: (1) "meaningful steps to obtain site control adequate to commence construction;" and (2) applying for interconnection.[72] A state could also require proof that a QF has applied and paid applicable fees for all necessary local permitting and zoning approvals.[73] The factors must be within the QF's control, so FERC clarified that it would only be appropriate for states to "require a QF to demonstrate that it is in the process of obtaining site control or has applied [and paid applicable fees] for all local permitting and zoning approvals, rather than requiring a QF to show that it has obtained site control or secured local permitting and zoning."[74] FERC stated that, by making clear that certain onerous conditions are not permitted, but describing which prerequisites a state may impose, it is "providing objective criteria to clarify when a LEO commences, which . . . will encourage the development of QFs."[75] FERC explained that, by providing more specific guidance, the Final Rule "creates greater certainty for QFs (and utilities) on this important element of QF development."[76] FERC also made clear that "nothing in the LEO rules . . . precludes any utility from choosing to execute a PPA before a QF has demonstrated compliance with the [new] LEO rules."[77]

While the majority voting for the Final Rule explains that it "is raising the bar to prevent speculative QFs from obtaining LEOs" and "is not establishing a barrier for financially committed developers seeking to develop commercially viable QFs,"[78] the bottom line is that FERC made it more difficult for certain QFs to establish LEOs. Establishing specific commercial viability criteria could be helpful for some projects, but by requiring that a developer has applied for permits and paid applicable fees before a LEO can arise, FERC has pushed out the LEO formation threshold, meaning that developers will need to do more work and take on more risk to get to an LEO than they did before.

5. Facilitation of Challenges to QF Certification and New Recertification Option for Rooftop Solar Owners

One method of obtaining QF status is through "self-certification," whereby an entity certifies using FERC Form No. 566 that its facility satisfies the requirements for QF status. While the other method—filing an application for FERC certification of QF status by order—involves notice in the Federal Register and a comment period, the self-certification procedure for most QFs does not.[79] Thus, to challenge a self-certification under FERC's existing regulations, an entity has to file a petition for declaratory order and pay the associated filing fee of more than $30,000.[80]

To reduce the burden on challengers, the NOPR proposed to "allow interested persons to intervene in, and to file a protest of a self-certification or self-recertification of a facility without the necessity of filing a separate petition for declaratory order and without having to pay the filing fee."[81] In the Final Rule, FERC determined to "allow an entity to challenge an initial self-certification or self-recertification without being required to file a separate petition for declaratory order and to pay the associated filing fee," but clarified that while "such protests may be made to new certifications," they will be allowed only for "self-recertifications and applications for Commission recertifications making substantive changes to the existing certification."[82] Substantive changes that could subject a recertification to protest include "a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or 5 percent . . . or a change in ownership in which an owner increases its equity interest by at least 10% from the equity interest previously reported."[83] This would include, for example, any change in direct ownership of the facility and arguably also would include any change in indirect (i.e., upstream) ownership, including passive ownership, of 10% or more. Recertification filings with only "administrative" changes are not be subject to protest.[84] Answers will be allowed.[85]

Removing the petition for declaratory order barrier to contesting a self-certification for QF status likely will result in more challenges to QF status.

FERC also adopted a helpful new recertification option for owners of rooftop solar PV facilities, which can present challenges because "[w]hen there are multiple co-owned rooftop solar PV systems within a mile, and thus at the same site, they may exceed 1 MW and therefore be required to file for certification or recertification [of QF status] unless they receive a waiver."[86] Specifically, "rather than be required to file for recertification each time the rooftop solar developer adds or removes a rooftop facility, a rooftop solar PV developer may recertify on a quarterly basis. . . . However, if in any quarter a rooftop solar PV developer either has no changes or only has changes of power production capacity of 1 MW or less, then it would not be required to recertify until it has accumulated changes greater than 1 MW total over the quarters since its last filing."[87] This change reduces a significant administrative burden for rooftop solar PV developers.

What Does It All Mean? – Potential Implications

The Final Rule likely will reduce the number of renewable energy projects eligible for small power production QF status; limit the number of projects deemed to have nondiscriminatory access to markets; restrict the availability of the mandatory purchase obligation benefits set forth in PURPA; increase regulatory uncertainty and costs for project developers; and slow the development of small renewable energy projects in many markets.

In addition, opening the "same site" analysis to challenge, and making such challenges possible by protest rather than an expensive petition for declaratory order, likely will increase litigation over the separateness of facilities. In light of these changes, developers of renewable energy projects will need to adjust their approach to developing and siting projects for which small power production QF status is important. Yet, even if they do so effectively, reduced access to PURPA contracts and markets and more difficult competitive procurement processes may increase risk just enough to preclude development of projects that previously were relatively low-risk.

That said, the news is not all bad. As noted, certain of FERC's reforms could actually increase small power production QF development. But the proof will be in states' implementation of the reforms. On balance, our view is that the changes are more negative than positive but could have been worse. QF developers and owners will need to be mindful of how the changes might affect their projects as existing QF contracts expire and it becomes necessary to negotiate new contracts with utility purchasers. And utilities now have increased leverage and options in state proceedings related to PURPA implementation.

Purchasers of small power production facilities will also need to be vigilant in their due diligence to identify and address, as needed, facilities that would not have raised "one-mile rule" issues when developed, but could raise such issues now if they become affiliated with other facilities as a result of a transaction. As always, owners of QFs and QF portfolios should monitor such matters and take action as needed to maintain compliance with FERC's regulations. In addition, in recent years, the increasing inclusion of battery storage in small power production QFs has generated questions regarding how to address storage in QF self-certifications, the relevance of storage to the small power production QF maximum and other size determinations, and whether storage counts as "electrical generating equipment" in a QF.

FERC does not resolve such questions in the Final Rule, finding that "the role of battery storage in QFs, including with regard to the distance between QFs, is beyond the scope in this proceeding."[88]

Developers and owners of QFs will need to familiarize themselves with revised Form No. 556, which will now include a variety of adjustments related to the substantive changes FERC made in the Final Rule.[89] Among other things, geographic coordinates will now be required for all facilities, rather than only those for which a street address is not provided, and applicants will need to identify only other affiliated small power production facilities within ten miles of the subject facility that use the same energy resource, as opposed to any affiliated facility within a mile, as was previously the case.[90] However, Form 556 now "will require the applicant to list the geographic coordinates of the nearest 'electrical generating equipment' of **both** its own facility and the affiliated small power production QF in question,"[91] which could be challenging in some instances.

Built on a fairly substantial record, including a technical conference and thousands of pages of comments from numerous, diverse stakeholders, the Final Rule seems likely to withstand appellate review. Nevertheless, a potential change in administration in January 2021 and changes to the composition of the Commission leave open the possibility that FERC could change course on certain aspects of the reforms in the relatively near future. Legislative action also could reverse some of the changes, as Reps. Pallone and Rush suggest. And it is possible that, on appeal, a federal appellate court could agree with Commissioner Glick that FERC did, in fact, attempt "via administrative fiat" what Congress has declined to do[92] and overturn it or remand it to FERC for adjustment.[93] Stay tuned.

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[1] *Qualifying Facility Rates & Requirements; Implementation Issues Under the Pub. Util. Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (2020) (Final Rule).

[2] Id. (Glick, Comm'r, dissenting in part at PP 1, 29).

[3] See *Qualifying Facility Rates & Requirements; Implementation Issues Under the Pub. Util. Regulatory Policies Act of 1978*, 168 FERC ¶ 61,184 (2019) (NOPR).

[4] See Press Release, Rep. Frank Pallone Jr., Pallone, Rush Condemn Partisan Action by FERC to Gut PURPA (July 20, 2020), https://energycommerce.house.gov/newsroom/press-releases/pallone-rush-condemn-partisan-action-by-ferc-to-gut-purpa.

[5] "Avoided cost" is what it would cost the utility to generate the electricity itself or purchase it from another source.

[6] See, e.g., Final Rule at P 20.

[7] See, e.g., id. PP 234, 253.

[8] Id. P 58.

[9] See, e.g., id. PP 59, 124, 151-54.

[10] See, e.g., id. PP 180-81, 189-94, 211-16.

[11] E.g., id. P 60.

[12] E.g., id. P 64.

[13] E.g., id. P 62.

[14] E.g., id. P 65.

[15] E.g., id. P 63.

[16] E.g., id. PP 10, 78, 83.

[17] Id. PP 66, 264.

[18] E.g., id. PP 97-98, 232.

[19] Id. P 100.

[20] Id. P 116.

[21] E.g., id. P 57 (emphasis added).

[22] Id.

[23] Id. P 58.

[24] Id. PP 59, 124, 151-52.

[25] Id. P 59, 180-81, 189-94, 211-16.

[26] Id. P 59.

[27] Id. P 21.

[28] Id. P 93.

[29] See id. PP 60, 361, 364-66, 411-14, 418, 420-38.

[30] Id. P 217.

[31] Id. P 227.

[32] Id.

[33] Id.

[34] Id. P 336.

[35] Id. P 296.

[36] Id. P 337.

[37] Id.

[38] Id. P 36 (emphasis in original).

[39] Id. (emphasis added).

[40] See id. PP 159, 167, 193.

[41] 18 C.F.R. § 292.204(a)(1) (2019).

[42] Id. § 292.204(a)(2).

[43] See, e.g., *N. Laramie Range Alliance*, 139 FERC ¶ 61,190, at PP 22-25 (2012).

[44] Final Rule at PP 466, 479.

[45] Id. P 472.

[46] Id. P 467.

[47] Id. P 469.

[48] Id. P 492.

[49] Id. P 509.

[50] Id. P 511.

[51] Id. P 514.

[52] Id. P 62.

[53] Id. P 521.

[54] Id.

[55] See 18 C.F.R. Part 292, Subpart F.

[56] Final Rule at PP 597, 625.

[57] Id. PP 64, 601, 625.

[58] Id. PP 597-98, 600.

[59] Id. PP 64, 600, 640.

[60] Id. P 641.

[61] Id.

[62] Id. P 645.

[63] Id. PP 597-98, 600, 629.

[64] See id. P 601.

[65] Id. P 659.

[66] Id. P 661.

[67] Id. P 98.

[68] NOPR at P 134.

[69] Final Rule at P 684.

[70] Id.

[71] Id. P 65.

[72] Id. P 685.

[73] Id.

[74] Id.

[75] Id. P 34.

[76] Id. P 33.

[77] Id. P 694.

[78] Id. P 688.

[79] NOPR at PP 144-45.

[80] See *Filing Fees*, https://www.ferc.gov/ferc-online/ferc-online/filing-fees (last updated June 29, 2020).

[81] Final Rule at PP 525.

[82] Id. P 63.

[83] Id. P 550.

[84] Id.

[85] Id. P 558.

[86] Id. P 559.

[87] Id. P 560.

[88] Id. P 524.

[89] See, e.g., id. P 698.

[90] See id. PP 584-96.

[91] Id. P 592 (emphasis added).

[92] Id. (Glick, Comm'r, dissenting in part at PP 2, 5).

[93] Id. (Glick, Comm'r, dissenting in part at P 5).

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