



PURPA

Title II Compliance Manual 2.0

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Preface



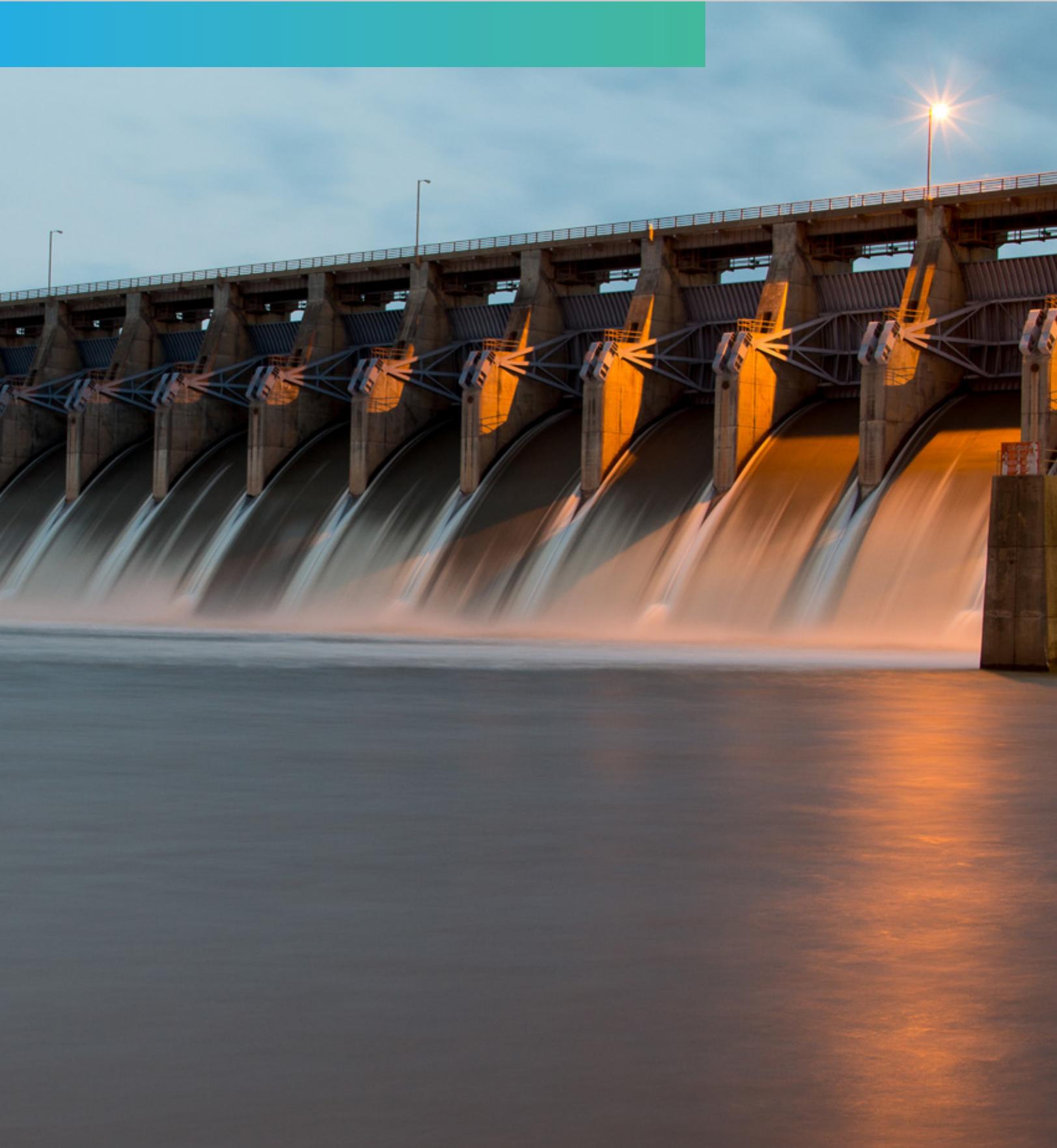
This Manual was sponsored by the **American Public Power Association (APPA)**, the **Edison Electric Institute (EEI)**, the **National Association of Regulatory Utility Commissioners (NARUC)**, and the **National Rural Electric Cooperative Association (NRECA)**.

The Manual is intended to be used as an aid to state commissions and utilities as they deal with issues related to the Public Utility Regulatory Policies Act (PURPA) of 1978, as amended, and in light of recent events and regulatory actions involving PURPA implementation.

This document is not intended to provide any recommendations for actions, decisions, or opinions from any of the sponsoring organizations, and does not constitute legal advice.

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Glossary of Acronyms



- ACC** – Arizona Corporation Commission
- CAISO** – California Independent System Operator Corporation
- CPUC** – California Public Utilities Commission
- EIM** – Energy Imbalance Market
- EPAct 2005** – Energy Policy Act of 2005
- ERCOT** – Electric Reliability Council of Texas, Inc.
- FERC** – Federal Energy Regulatory Commission
- FIT** – Feed-In Tariff
- FPA** – Federal Power Act
- GIA** – Generator Interconnection Agreement
- GOL** – Generator Operator Limits
- G&T** – Generation and Transmission
- ISO** – Independent System Operator
- ISO-NE** – ISO New England Inc.
- LEO** – Legally Enforceable Obligation
- LMP** – Locational Marginal Price
- MISO** – Midcontinent Independent System Operator, Inc.
- MOA** – Memorandum of Agreement
- MW** – Megawatt
- NOPR** – Notice of Proposed Rulemaking
- NYISO** – New York Independent System Operator, Inc.
- OATT** – Open Access Transmission Tariff
- OPEC** – Organization of the Petroleum Exporting Countries
- PJM** – PJM Interconnection, L.L.C.
- PPA** – Power Purchase Agreement
- PSC** – Public Service Commission
- PUC** – Public Utility/ies Commission
- PUHCA** – Public Utility Holding Company Act
- PURPA** – Public Utility Regulatory Policies Act of 1978
- PV** – Photovoltaic
- QF** – Qualifying Facility
- RAM** – Renewable Auction Mechanism
- Re-MAT** – Renewable Market Adjusting Tariff
- REC** – Renewable Energy Credit/Certificate
- RFP** – Request for Proposal(s)
- RTO** – Regional Transmission Organization
- SPP** – Southwest Power Pool, Inc.
- TLR** – Transmission Loading Relief



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I. Introduction

A. OVERVIEW OF PURPA AND RECENT DEVELOPMENTS

The Public Utility Regulatory Policies Act of 1978 (“PURPA”) was signed into law by President Carter more than forty years ago. A lengthy piece of legislation that addressed multiple issues, PURPA is, perhaps, best known among energy industry professionals for the provisions of section 210 within Title II, under which electric utilities must purchase the output of certain renewable and cogeneration resources—referred to as “qualifying facilities” or “QFs”—at regulated prices. Section 210 of PURPA was originally intended to facilitate the development of domestic renewable energy in the face of concerns regarding the United States’ dependence on foreign petroleum and dwindling natural gas supply, both circumstances that are difficult to appreciate now given the massive expansion of shale oil and natural gas production, and the reduction in petroleum generation as a percentage of our national resource mix down to *de minimis* levels.

Fast forwarding to today, much has changed within the energy industry relative to the late 1970s and early 1980s, when the Federal Energy Regulatory Commission (“FERC” or the “Commission”) adopted its initial implementing regulations for PURPA section 210. The maturation of certain renewable technologies, including solar and wind generation, coupled with a state-level focus on environmental issues that has led to policies such as renewable portfolio standards, has contributed to significantly wider deployment of renewable resources. At the same time, the regulated markets for energy and capacity have likewise matured, and FERC’s market-oriented policies have encouraged, and in some cases required, the development of rules that accommodate all types of generation technologies. This confluence of factors has presented both challenges and new opportunities for electric utilities of all types that are subject to PURPA, including investor owned utilities, public power, and rural electric cooperatives; for federal, state, and local regulators that are responsible for PURPA implementation and oversight; and





for renewable power producers that may avail themselves of PURPA as a pathway to resource development.

Responding to calls for reform, in 2020, FERC issued its landmark Order Nos. 872 and 872-A, which together represent the first significant revision to its PURPA regulations in decades and a major advancement in FERC's PURPA policies to reflect contemporary market and technological realities. These orders integrate market principles into its PURPA pricing policies, reduce the threshold for presumed energy and capacity market participation by qualifying facilities, and update and revise the qualification criteria for certain types of PURPA qualifying facilities.

This Manual, which discusses section 210 within Title II of PURPA and associated regulations, focuses in large part on current FERC policies and recent and emerging issues, particularly those that touch on the topics that FERC addressed in Order No. 872. As regulators, electric utilities, and qualifying facilities implement Order No. 872 and continue to comply with those elements of PURPA section 210 and FERC's regulations that are unaffected by Order No. 872, FERC's policies, and those of implementing states and local regulatory authorities, will undoubtedly continue to evolve, as will renewable resource technologies and the state of the energy markets.

B. HOW TO USE THIS MANUAL

This Manual is intended to be a resource for legal practitioners in search of a starting point into research on a particular topic, regulators seeking insight into broader matters of federal and state PURPA policies as well industry trends, and non-legal professionals within the industry who are looking to gain a greater understanding of electric utilities' compliance obligations to inform resource planning and procurement decisions. The Manual provides a "deep dive" into particular issues for readers who are seeking an in-depth discussion of case law and FERC precedent, and it also can be used by those who only require an overview or the key points of particular issues. For topics of central importance, the Manual includes several short, bullet-point style outlines of key regulations and requirements. At the end of the Manual is an appendix of PURPA section 210 and the FERC regulations, as well as a cross-walk of topical references that, along with the table of contents, are intended to simplify the process of locating the Manual's discussion of a particular subject.

Immediately below is a "Frequently-Asked Questions" section that can be used as a summary of major PURPA requirements and policies, as amended under Order No. 872. Section I.D. provides an overview and summary of PURPA and FERC's major orders relating to PURPA. Section I.E. discusses the unique way in which federal and state actions interrelate for purposes of PURPA.

Section II generally focuses on key legal requirements under PURPA. Starting with Sections II.A., II.B., and II.C., the Manual provides a detailed overview of FERC's

PURPA regulations as they relate to qualifying facilities, including the applicable criteria for attaining QF status, as well as an overview of the obligations of electric utilities.

Section II.D. includes a discussion of avoided cost pricing, which is one of the more controversial aspects of PURPA. This section focuses on the significant changes to FERC's PURPA pricing policies that were adopted in Order No. 872.

Sections II.E. through II.K address various implementation issues, including, for example, contract terms, legally enforceable obligations, market participation, and interconnection and operational issues.

Finally, Section II.L. addresses PURPA's complicated enforcement scheme and provides an overview of key cases and precedent addressing enforcement related topics.



C. PURPA COMPLIANCE AND IMPLEMENTATION: FREQUENTLY ASKED QUESTIONS

1. PURPA FUNDAMENTALS

What is PURPA?

The Public Utility Regulatory Policies Act of 1978, or "PURPA" was passed in response to the energy crises of the 1970s, as part of legislation referred to as the National Energy Act that was intended to reduce U.S. dependence on fossil fuels. PURPA was intended to promote conservation, reliability, competition and efficiency in the generation and delivery of electricity of electric energy. The statute encourages development of alternative generation resources that do not rely on fossil fuels. PURPA also requires that the rates for electric energy from facilities that qualify for the benefits of PURPA must be just and reasonable to consumers and must not be discriminatory against such facilities.

What is a Qualifying Facility ("QF")?

A QF is a small power production facility or a cogeneration facility that meets the requirements of PURPA. FERC's regulations also provide specific criteria and requirements for small power production facilities and cogeneration facilities. See Section II.B.

For purposes of PURPA, what is a small power production facility?

A small power production facility is an eligible solar, wind, waste or geothermal facility or a facility that produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources (including hydroelectric), geothermal resources, or

any combination thereof; and has a power production capacity that, together with any other facilities located at the same site (as determined by FERC), is not greater than 80 MWs. See Section II.B.1.

For purposes of PURPA, what is a cogeneration facility?

A cogeneration facility is generally defined as a facility that produces electric energy, and steam or other forms of useful energy (such as heat), that are used for industrial, commercial, heating or cooling purposes. See Section II.B.2.

What are the criteria for qualifying small power production facilities?

A small power production facility is a QF if it (1) has a power production capacity of not greater than 80 MWs at the same site; (2) has a primary energy source of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and (3) unless exempted, has filed with FERC a notice of self-certification or an application for FERC certification that has been granted. See Section II.B.1.

What is the "one mile rule?"

Qualifying small power production facilities are subject to a power production capacity limitation of no more than 80 MW at the "same site." The one-mile rule provides that facilities are considered to be at the "same site" if the facilities are owned by the same or affiliated entities, use the same energy resource, and are located within one mile of the facility for which the QF status is sought. See Section II.B.1.a)ii.

What are the criteria for qualifying cogeneration facilities?

Cogeneration facilities are characterized as topping-cycle or bottoming-cycle based on the order in which energy input to the facility and the reject energy are used for power production or thermal energy. Cogeneration facilities are subject to complex criteria depending on the type of cogeneration facility, as well as requirements regarding how the output of the facility is used. Similar to qualifying small power production facilities, in order to obtain QF status (unless exempt), a cogeneration facility must file with FERC either a notice of self-certification or an application for certification, the latter of which must have been granted by FERC. Unlike small power production facility QFs, there is no size limitation on cogeneration QFs. See Section II.B.1 and cross-reference the diagram on page 49.

How does an entity obtain qualifying facility status?

There are two options for an entity to obtain QF status: self-certification (or re-certification), which is obtained by filing a form with FERC; and FERC certification, which involves issuance of an order by FERC on an application request submitted by the QF. QFs with a net power production capacity of 1 MW or less, however, are not required to take any action to obtain QF status. See Section II.B.4.

What are the requirements for electric utilities as related to qualifying facilities?

The electric utility obligations are set forth in FERC's PURPA regulations, and include the following: (1) the obligation to

make available avoided cost data; (2) the obligation to purchase energy and capacity from QFs; (3) the obligation to sell energy to QFs; (4) the obligation to interconnect; and (5) the obligation to operate in parallel. See Section II.C. Although all of these PURPA requirements can affect electric utility planning, operations and costs, the obligation for electric utilities to purchase electric energy and capacity offered by QFs at the utility's "avoided cost" has generally been most impactful on electric utilities and has generated the most debate and controversy in its implementation.

What types of electric utilities are subject to PURPA's requirements?

PURPA defines the term "electric utility" broadly to include companies and federal and state agencies that sell electric energy. Investor-owned electric companies, public power utilities and electric cooperatives are all "electric utilities" for purposes of PURPA.

PURPA imposes a mandatory purchase obligation on electric utilities, but what if an electric utility does not need energy or capacity offered by a QF?

Electric utilities are generally obligated to take energy and capacity offered by QFs, regardless of whether the utility needs the energy or capacity, and utilities have very limited rights to curtail mandatory QF purchases under FERC's regulations. A lack of need for new energy or capacity, however, may affect the avoided cost rate the QF is entitled to receive (see "Basics of Avoided Cost" below).

2. THE BASICS OF AVOIDED COST

What is the required compensation for electric utility purchases from QFs?

The PURPA statute does not specify an exact rate for QF energy and capacity, although it provides that rates paid to QFs may not exceed “the incremental cost to the electric utility of alternative electric energy.” FERC’s PURPA regulations implement this provision by requiring that QFs be compensated by electric utilities at the “avoided cost.” The term “avoided cost” refers to the cost of an electric utility’s alternative sources of energy or capacity that the electric utility would generate or construct itself or purchase from another source, such as an independent power producer or an energy market. FERC’s regulations also list other factors that may be considered in establishing the avoided cost rate, including, for example, how reliable the QF may be or whether it is dispatchable. Although electric utilities and QFs can negotiate for rates that are different from the electric utility’s avoided costs, there is no requirement in PURPA that an electric utility pay more than avoided costs to purchase the QF energy and capacity. See Section II.D.

When is the avoided cost determined?

It depends. FERC’s regulations allow QFs to choose whether they are compensated based on the electric utility’s avoided costs at the time the QF output is delivered or at the time a QF invokes its right to require the electric utility to purchase its energy and capacity pursuant to a legally enforceable obligation. However, Order No. 872 permits state regulatory authorities

and nonregulated electric utilities to determine whether fixed avoided cost rates for energy under legally enforceable obligations may be used as a measure of avoided cost, or whether such rates will be variable. See Section II.D.

Who sets avoided cost rates?

In general, avoided cost rates are set by state utility commissions based on standards established by FERC. Electric utilities whose rates are not regulated by state public utility commissions may set their own avoided cost rates based on the FERC standards. These “nonregulated electric utilities” include most municipal utilities and electric cooperatives.

Can market prices be used to set avoided cost rates?

Yes, electric utilities may use locational marginal prices from regulated energy markets as their avoided cost energy rates. Electric utilities that operate outside of an organized energy market may reference competitive prices from liquid market hubs as a measure of avoided energy costs. Moreover, these energy rates may vary over the term of a QF purchase. QFs may contest the use of market prices to set avoided cost energy rates, but the QF would need to demonstrate with evidence that these market prices do not represent the electric utility’s true avoided costs. See Sections II.D.1., II.D.2., and II.D.5.

Are competitive solicitation processes or request for proposal processes permissible for use in setting avoided cost rates?

Yes. FERC has explained that these types of processes can provide a price signal

as to avoided costs, but only if these processes take place using procedures that are designed to ensure that the solicitation process is open, transparent, and nondiscriminatory. See Section II.D.6.

What is an electric utility's avoided cost if the utility does not need energy or capacity?

If an electric utility does not need capacity, the avoided cost rate for capacity may be set at \$0, because it is unable to avoid any costs for capacity procurement through a QF purchase. The situation is less clear with respect to a lack of need for energy; historically, electric utilities have been presumed to require energy. FERC has not directly addressed this issue to date. See Section II.D.8.

3. LEGALLY ENFORCEABLE OBLIGATIONS

Is a QF required to have a power purchase agreement in place in order to create a legally enforceable obligation for an interconnected utility to purchase the QF's output?

No. A legally enforceable obligation to purchase a QF's output is formed based on a QF's commitment to sell, rather than any action taken by the utility. It cannot be conditioned on the signing of a power purchase agreement. See Section II.E.1.

Are there any criteria required for a QF to show that it is eligible for a legally enforceable obligation?

Yes. QFs must show that they are commercially viable and make certain financial commitments to construct their

proposed project before they can create a legally enforceable obligation for an electric utility to purchase the QF's output. See Section II.E.2.

4. TERMINATION, WAIVER, AND MARKETS

Are there any circumstances that would allow an electric utility to terminate or waive its obligation to purchase from a QF?

Yes. Utilities may propose to terminate their must-purchase obligation on a case-by-case basis by filing a request with FERC. Electric utilities are not required to purchase from a QF if FERC finds that the QF has nondiscriminatory access to markets, including organized markets and liquid market hubs. An electric utility may also seek waiver of its must-purchase obligation. See Sections II.F.1 and II.F.2.

5. INTERCONNECTION

Is an electric utility required to interconnect with a QF?

Under FERC's regulations, an electric utility is generally required to interconnect with a QF for purposes of purchasing the energy and capacity made available from that QF. See Section II.G.1.

What are the rules governing the interconnection of a qualifying facility?

The interconnection process and rules are detailed in FERC's Small Generator Interconnection procedures, available at [Standard Interconnection Agreements and Procedures for Small Generators](#) |

Federal Energy Regulatory Commission (ferc.gov). Many states have developed their own interconnection procedures. Others may look to FERC's procedures as a model for developing their own. See Section II.G.1.

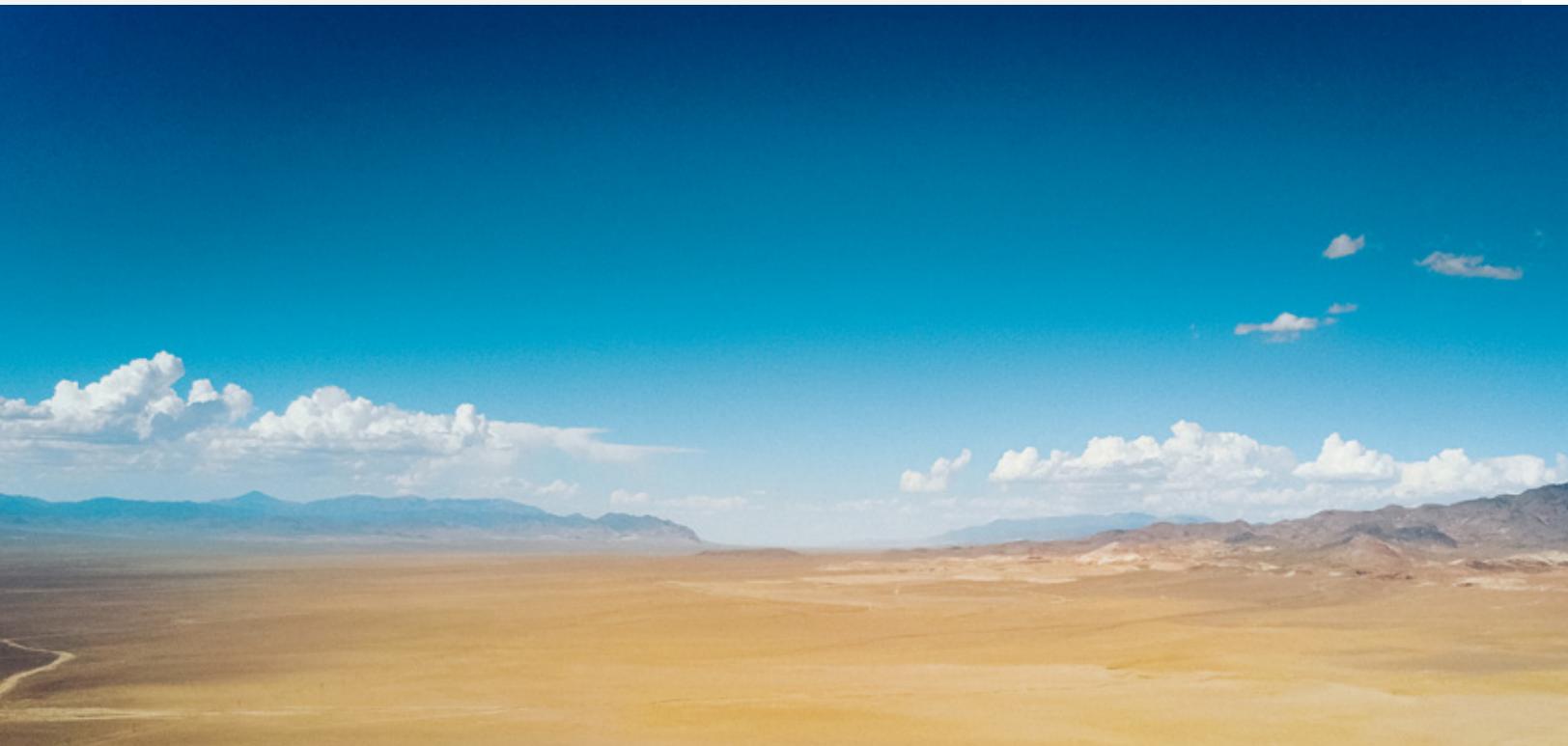
Who pays the costs to interconnect a qualifying facility?

Each QF is obligated to pay its interconnection costs. For regulated utilities, the state regulatory authority with ratemaking authority over the utility is responsible for determining the manner in which costs are assessed. Nonregulated utilities may determine the interconnection related costs but must do so on a nondiscriminatory basis. See Section II.G.3.

6. NET METERING AND FEED-IN TARIFFS

What is net metering and how does it work?

Net metering is an incentive compensation mechanism that is outside the scope of PURPA. It allows a residential or business customer to use the energy produced from distributed generation (typically private rooftop solar installations) to (i) consume that power on-site, thereby reducing the amount of energy purchased from an interconnected utility, and (ii) sell excess power back to the utility to be injected into the power grid. The customer is billed for the "net" energy used each month, which represents the difference between the energy produced on-site and the energy consumed over the course of the applicable billing period. See Section II.H.



What is a feed-in tariff?

A feed-in tariff is a type of long-term contract designed to incentivize the development of renewable energy sources by providing a fixed, per-unit price for electricity sold into the grid. A feed-in tariff may be a proxy for calculating avoided costs. The form of feed-in tariffs can vary greatly from state to state and may be tailored to the type of renewable technology employed to produce the energy. See Section II.I.

How is PURPA relevant to net metering arrangements and feed-in tariffs?

Because the resources that participate in net metering arrangements and feed-in tariff programs may be QFs under PURPA, it is important to consider any PURPA implications in designing and implementing these compensation programs. See Sections II.H-I.

7. OPERATIONS

Does an electric utility's must-sell obligation require it to provide any additional services to a QF?

Yes. An electric utility with an obligation to sell power to a QF also has an obligation to provide supplemental power, back-up power, maintenance power, and interruptible power upon the QF's request. Rates for these services are to be based on system-wide costing principles and are to be nondiscriminatory. See Section II.K.1.

May an electric utility curtail QF power?

An electric utility may only curtail QF power (1) in the case of a system emergency, or (2) during light loading situations, so long as the electric utility is purchasing from a QF on an as-available basis, rather than pursuant to a long-term PPA. See Section II.K.2

8. ENFORCEMENT

Is PURPA enforced by FERC or by state regulatory authorities?

Both. PURPA includes a complex enforcement scheme of cooperative federalism that divides jurisdiction between state and federal authorities. Depending on the nature of the alleged PURPA violation, a decision may be challenged as inconsistent with PURPA, FERC's, or a state's requirements by: (1) bringing a proceeding before the relevant state regulatory authority or governing body; (2) filing for judicial review of any state regulatory proceeding in state court; or, (3) filing a petition for enforcement against the state regulatory authority or nonregulated electric utility at FERC, and, if FERC chooses not to act, filing a petition against the state or nonregulated electric utility in U.S. district court. See Section II.L.



D. REGULATORY BACKGROUND AND AUTHORITY UNDER PURPA SECTIONS 201 AND 210 AND FERC'S IMPLEMENTATION ORDERS

1. STATUTORY REVIEW

Signed into law by President Carter in 1978, PURPA comprised Part V¹ of a legislative package entitled the National Energy Act² that was designed to combat the nationwide “energy crisis” of the 1970s. This turbulent historical context included the oil embargo imposed by the Organization of Petroleum Exporting Countries (“OPEC”) against the United States.³ During an era in which the U.S. was importing approximately 50 percent of its oil from foreign suppliers, the OPEC oil embargo resulted in cessation of oil shipments from the Middle East to the U.S. for a period spanning October 1973 to March 1974.⁴ Likewise, the U.S. experienced an acute shortage in the supply of natural gas, as domestic production declined dramatically due to the high cost of extraction and suppressed producer prices.⁵

These factors contributed to an approximately 400 percent increase in the cost of oil and an approximately 175 percent increase in the cost of natural gas over the five-year period spanning 1972 to 1977.⁶ At the time, approximately one-third of electricity generated in the U.S. was derived from

oil and natural gas, with oil constituting approximately 16 percent of the total fuel used in electricity generation.⁷ The effects of increasing fuel costs in the electric generation sector—coupled with increasing costs per kilowatt (“kW”) of new plant capacity—inspired unprecedented national concern for conservation of oil and gas, energy efficiency, and fuel diversity.⁸

Recognizing these myriad pressures, President Carter advocated for the need to promote U.S. fuel diversity and independence:

The oil and natural gas that we rely on for 75 percent of our energy are simply running out. In spite of increased effort, domestic production has been dropping steadily at about 6 percent a year. Imports have doubled in the last 5 years. Our Nation's economic and political independence is becoming increasingly vulnerable. Unless profound changes are made to lower oil consumption, we now believe that early in the 1980's the world will be demanding more oil than it can produce.⁹

1 Pub. L. No. 95-617, 92 Stat. 3117.

2 In addition to PURPA, the package included: the Energy Tax Act of 1978, Pub. L. No. 95-618, 92 Stat. 3174; the National Energy Conservation Policy Act, Pub. L. No. 95-619, 92 Stat. 3206; the Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 95-620, 92 Stat. 3289; and the Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3351.

3 LEONARD MAUGER, *THE AGE OF OIL: THE MYTHOLOGY, HISTORY, AND FUTURE OF THE WORLD'S MOST CONTROVERSIAL RESOURCE* 112-16 (2006).

4 REGINA ANNE KELLY, *ENERGY SUPPLY AND RENEWABLE RESOURCES* 380 (2007); Brad Sherman, *A Time to Act Anew: A Historical Perspective on Energy Policy Act of 2005 and the Changing Electrical Energy Market*, 31 WM. & MARY ENVTL. L. & POL'Y REV. 211, 214 (2006); Ross D. Ain, *PURPA: Federal Energy Policy Impacting on the State Regulatory Domain*, 104 PUB. UTIL. L. 18, 18 (1979).

5 See Richard J. Pierce, Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 25 ENERGY L.J. 57, 64-65 (2004).

6 S. Rep. No. 95-442, at p. 9 (1977).

7 S. Rep. No. 95-361, at p. 32 (1977).

8 S. Rep. No. 95-442, at p. 9; see also Richard D. Cudahy, *PURPA: The Intersection of Competition and Regulatory Policy*, 16 ENERGY L.J. 419, 421 (1995).

9 President Carter, Address to the Nation on Energy (Apr. 18, 1977).

Ultimately, Congress determined that facilitating cogeneration and small power production through the various provisions of PURPA would help reduce U.S. dependence on traditional fossil fuels (including foreign oil) while controlling energy costs.¹⁰

Formally, PURPA's statutory text recognized three goals: (1) to encourage the "conservation of energy supplied by electric utilities"; (2) to encourage the "optimization of the efficiency of use of facilities and resources

by electric utilities"; and (3) to encourage "equitable rates to electric consumers."¹¹ To these ends, Title I of PURPA required state regulatory commissions and nonregulated electric utilities to evaluate implementation of a number of federal ratemaking standards, including those related to consumer rate design¹² and load management techniques.¹³ Moreover, Title II of PURPA contained provisions intended to facilitate the entry of alternative energy sources into the electric generation market.¹⁴

¹⁰ S. Rep. No. 95-442, at pp. 21, 23.

¹¹ Currently codified at 16 U.S.C. § 2611 (2020).

¹² *Id.* at §§ 2621(a), (d)(1)-(5) (establishing federal standards for cost-of-service, declining block rates, time-of-day rates, seasonal rates, and interruptible rates).

¹³ *Id.* at § 2621(d)(6) ("Each electric utility shall offer to its electric consumers such load management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will—(A) be practicable and cost-effective, as determined under section 2625(c) of this title, (B) be reliable, and (C) provide useful energy or capacity management advantages to the electric utility.").

¹⁴ 16 U.S.C. §§ 796, 824a-3(a). Analysts have characterized Title II of PURPA as opening the door to competition among new entrants to the electric generation market and incumbent utilities, thus ending the "monopoly control" enjoyed by these traditionally-regulated entities. See RICHARD F. HIRSH, *POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM* 23 (1999); PETER Z. GROSSMAN & DANIEL H. COLE (EDS.), *THE END OF A NATURAL MONOPOLY: DEREGULATION AND COMPETITION IN THE ELECTRIC POWER INDUSTRY* (2003).



In particular, PURPA section 210(a) required FERC to prescribe rules under which electric utilities are obligated to offer to sell energy and capacity to qualifying cogeneration and small power production facilities (collectively, “qualifying facilities” or “QFs”) as well as to purchase energy and capacity from such facilities.¹⁵ Under the statute, “cogeneration facility” means a facility that produces both electricity and steam or another form of useful energy, such as heat, that is used for industrial, commercial, heating, or cooling purposes.¹⁶ Additionally, “small power production facility” means a facility that produces electricity solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof and has a power production capacity which, together with any other facilities located at the same site, as determined by FERC, is not greater than 80 megawatts (“MW”).¹⁷ The statute originally imposed an ownership limitation, specifying that no more than 50 percent of a QF could be owned by an electric utility, although such requirement was subsequently eliminated by the Energy Policy Act of 2005 (“EPAAct 2005”).¹⁸ The statute also directed FERC to develop other qualifying criteria and procedures for obtaining QF status, which are thoroughly examined in Section II.C.

As a corollary to the mandatory purchase obligation, PURPA section 210(b) required that the rates paid by utilities for the energy and capacity purchased from QFs should be just and reasonable to the utility’s electric consumers and in the public interest, and should not discriminate against QFs.¹⁹ Notably, FERC may not promulgate rules providing for rates that “exceed[] the incremental cost to the electric utility of alternative electric energy.”²⁰ Commonly referred to as the utility’s “avoided cost,” this limiting principle is designed to protect customers, while limiting compensation of QFs to a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from the QF, rather than self-generating an equivalent amount of energy or purchasing the energy or capacity from other suppliers. Avoided cost pricing thus reflects a policy of consumer indifference, whereby electric utility customers are protected from increased costs due to the utility’s purchase of QF output.²¹

Finally, PURPA section 210(e) exempted QFs from provisions of the Federal Power Act (“FPA”), Public Utility Holding Company Act of 1935 (“PUHCA”), and from state laws concerning utility rates and financial organization.²² PURPA also directed that

15 16 U.S.C. § 824a-3(a).

16 *Id.* at § 824a-3(l). The statutory definition provides specifically that “‘cogeneration facility’ means a facility which produces—(i) electric energy, and (ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.” *Id.* (cross-referencing 16 U.S.C. § 796(18)).

17 *Id.* at § 824a-3(l). The statutory definition provides specifically that “‘small power production facility’ means a facility which is an eligible solar, wind, waste, or geothermal facility, or a facility which—(i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and (ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts.” *Id.* (cross-referencing 16 U.S.C. § 796(17)).

18 Pub. L. No. 109-58, 119 Stat. 594.

19 16 U.S.C. § 824a-3(b).

20 *Id.*

21 See Peter Fox-Penner, *Efficiency and the Public Interest: QF Transmission and the Energy Policy Act of 1992*, 14 ENERGY L.J. 51, 55 (1993) (“It is evident from the construction of these provisions that Congress intended to provide an economic encouragement to QFs, while leaving utility customers indifferent to obtaining electricity from a QF and from the utility’s alternative source. The encouragement comes about through the QF’s entitlement to receive [full avoided cost (“FAC”)] regardless of its own cost of production. Any QF able to produce power at an average cost lower than its utility’s FAC is entitled to keep the difference as profit”).

22 16 U.S.C. § 824a-3(e).

state regulatory authorities and nonregulated electric utilities implement any rules prescribed by FERC concerning electric utilities' obligation to purchase power from QFs.²³

In the decades following PURPA's enactment, implementing orders by FERC and subsequent Congressional amendments have shaped and re-shaped the contours of its original requirements. A number of these landmark developments are outlined in the following subsections.

2. FERC ORDER NOS. 69 AND 70

The original FERC rules implementing PURPA sections 210 and 201 were issued in FERC Order Nos. 69²⁴ and 70.²⁵ These orders continue to form the core of FERC's PURPA policies, although certain regulations resulting from these orders have since been retired.

In Order No. 69, dated February 19, 1980, FERC issued rules implementing the standards for avoided cost rates for sales of electric power between QFs and electric utilities. It also established exemptions for certain QFs from most federal and state regulations governing electric utilities. Order No. 69 explained that prior to PURPA's

enactment, cogenerators and small power producers seeking to interconnect with electric utilities faced three major obstacles: (1) electric utilities were not required to purchase the electric output nor to offer an appropriate rate; (2) electric utilities were not prohibited from charging discriminatorily high rates for back-up service; and (3) cogenerators and small power producers ran the risk of triggering federal and state regulations applicable to electric utilities by virtue of supplying electricity to the utility's grid.²⁶ To alleviate these burdens, FERC clarified that QF purchase rates are to equal the utility's avoided cost and directed state regulatory authorities and nonregulated electric utilities to determine such costs consistent with factors laid out in the regulations.²⁷ FERC also set forth other required arrangements between electric utilities and QFs pursuant to PURPA section 210. Importantly, Order No. 69 established utility obligations with respect to QFs—including mandatory purchases and nondiscriminatory provision of interconnection, transmission, and supplementary services—and with respect to availability and transparency of utility system cost data.²⁸ FERC delegated to state regulatory authorities and nonregulated electric utilities the responsibility to determine avoided costs and interconnection costs and

23 *Id.* at § 824a-3(f).

24 *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 FR 12214 (Feb. 25, 1980), FERC Stats. & Regs. ¶ 30,128 (cross-referenced at 10 FERC ¶ 61,150) ("Order No. 69"), *order on reh'g*, Order No. 69-A, 45 FR 33958 (May 21, 1980), FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166) ("Order No. 69-A"), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

25 *Small Power Production and Cogeneration Facilities – Qualifying Status*, Order No. 70, 45 FR 17959 (Mar. 20, 1980), FERC Stats. & Regs. ¶ 30,134 (cross-referenced at 10 FERC ¶ 61,230) ("Order No. 70"), *orders on reh'g*, Order No. 70-A, 45 FR 33603 (May 20, 1980), FERC Stats. & Regs. ¶ 30,159 (cross-referenced at 11 FERC ¶ 61,119) and FERC Stats. & Regs. ¶ 30,160 (cross-referenced at 11 FERC ¶ 61,166) ("Order No. 70-A"), *order on reh'g*, Order No. 70-B, 45 FR 52779 (Aug. 8, 1980), FERC Stats. & Regs. ¶ 30,176 (cross-referenced at 12 FERC ¶ 61,128) ("Order No. 70-B"), *order on reh'g*, Order No. 70-C, 45 FR 66787 (Oct. 8, 1980), FERC Stats. & Regs. ¶ 30,192 (1980) (cross-referenced at 12 FERC ¶ 61,306) (Order No. 70-C"), *amending regulations*, Order No. 70-D, 46 FR 11251 (Feb. 6, 1981), FERC Stats. & Regs. ¶ 30,234 (cross-referenced at 14 FERC ¶ 61,076) ("Order No. 70-D"), *amending regulations*, Order No. 70-E, FERC Stats. & Regs. ¶ 30,274 (1981) (cross-referenced at 15 FERC ¶ 61,281) ("Order No. 70-E").

26 Order No. 69, 45 FR at 12217.

27 *Id.* at 12215-16, 12226.

28 *Id.* at 12218, 12219-21.

to set rates for the sale of supplementary, back-up, maintenance, and interruptible power service to QFs.²⁹

While Part 292, Subpart C³⁰ of FERC's new regulations dictated sales and purchases of electric energy and capacity between electric utilities and QFs, and actions related to such sales and purchases, Order No. 69 expressed FERC's view at the time that the rate provisions of PURPA section 210 apply only if the QF "chooses to avail itself of that section."³¹ Accordingly, Subpart C did not preclude negotiated agreements between electric utilities and QFs that contain rates, terms, or conditions different from those set forth in the rules.³² Similarly, Subpart C did not affect the validity of any contract entered into between an electric utility and a QF for any purchase.³³

In Order No. 69-A, FERC largely affirmed its prior order. With respect to the transportation (i.e., wheeling) of QF energy and capacity, however, FERC clarified that an electric utility that transmits energy from a QF to another electric utility is permitted to receive reimbursement for this transmission service.³⁴ Under the regulations, if a QF agrees, an electric utility that would otherwise be obligated to purchase energy or capacity from a QF may transmit (i.e., "wheel") the energy or capacity to another electric utility.³⁵ Order No. 69-A explained that nothing in the regulations

prohibits the wheeling utility from charging a nondiscriminatory transmission rate for its transmission service.³⁶ Moreover, Order No. 69-A clarified that the purchasing utility is required only to purchase such energy or capacity at a rate reflecting its avoided cost, and any costs incurred to deliver the energy or capacity via another utility's transmission system are the responsibility of the selling QF.³⁷ FERC noted, however, that the wheeling utility may agree to bear some or all of the transmission costs.³⁸

In Order No. 70, dated March 13, 1980, FERC issued rules establishing the criteria and procedures for obtaining QF status and thereby obtaining the special rates, rights, and regulatory exemptions under Order No. 69. FERC declined to impose a filing requirement and case-by-case determination for facilities seeking QF status; rather, Order No. 70 provided that any cogeneration or small power production facility meeting the requirements set forth in the regulations automatically qualified as a QF.³⁹ Utilities, state regulatory authorities, and other interested parties retained the right to challenge such self-determinations by filing a petition for declaratory order with FERC.⁴⁰ Alternatively, Order No. 70 established an optional procedure pursuant to which the owner or operator of a QF may file an application for Commission certification of QF status.⁴¹

29 *Id.* at 12216.

30 Currently codified at 18 C.F.R. § 292.301(a) (2021).

31 Order No. 69, 45 FR at 12217.

32 18 C.F.R. § 292.301(b)(1).

33 *Id.* at § 292.301(b)(2).

34 Order No. 69-A, 45 FR at 33960.

35 18 C.F.R. § 292.303(d).

36 Order No. 69-A, 45 FR at 33960.

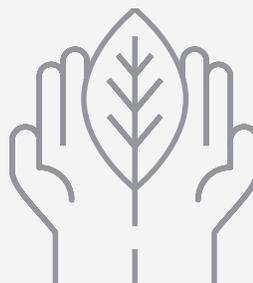
37 *Id.* at 33960.

38 *Id.* at 33960.

39 Order No. 70, 45 FR at 17960, 17962-63.

40 *Id.* at 17962.

41 *Id.* at 17960, 17962-63.



Order No. 70 also elaborated on the statutory definitions of “cogeneration facility” and “small power production facility,” including, originally, qualifying criteria related to operating and efficiency standards and facility ownership.⁴² To implement the statutory requirement that the power production capacity of a small power production facility not exceed 80 MW at any site, FERC established a rebuttable presumption that all facilities that use the same energy resource, are owned by the same person, and are located within one mile of each other be considered together for purposes of calculating capacity.⁴³ Known colloquially as the “one-mile” rule, separate facilities less than one mile apart were deemed to be located at the same site and thus were limited to 80 MW capacity in the aggregate in order to satisfy the QF criteria.⁴⁴

Subsequently, Order No. 70-A provided that applications for Commission certification of QF status contain a notice for publication in the Federal Register.⁴⁵ Order No. 70-B amended the regulations to permit ownership of QFs by gas utility holding companies,⁴⁶ and Order No. 70-C amended the regulations to provide that electric utility holding companies that qualified for an exemption under PUHCA sections 3(a)(3) or 3(a)(5) were not subject to the 50 percent ownership limitation.⁴⁷ As explained in Order No. 70-C, PUHCA section 3(a)(5) granted an exemption to holding companies that did not derive any material part of their income from any public utility company operating in the U.S., while section

3(a)(3) granted an exemption to holding companies that were “only incidentally [] holding company[ies], being primarily engaged or interested in one or more businesses other than the business of a public utility company.”⁴⁸ Order No. 70-D later amended the regulations again to permit up to 100 percent ownership of QFs by electric utilities that were not “primarily engaged in either the generation or sale of electric energy.”⁴⁹ Additionally, subsidiaries of PUHCA section 3(a)(3) or 3(a)(5) exempt electric utility holding companies were permitted to own up to 100 percent of a QF whether or not the subsidiary was “primarily engaged in” the generation or sale of electric power.⁵⁰



42 *Id.* at 17960, 17963.

43 *Id.* at 17965-66.

44 *Id.* at 17965.

45 Order No. 70-A, 45 FR at 33603.

46 Order No. 70-B, 45 FR at 52779-80.

47 Order No. 70-C, 45 FR at 66787.

48 *Id.* at 66787-88.

49 Order No. 70-D, 46 FR at 11252-53.

50 *Id.* at 11252.

3. EPACK 2005

Since issuing its landmark Order Nos. 69 and 70, FERC intermittently has revised its regulations under PURPA sections 201 and 210 to reflect changes in federal law.⁵¹ In particular, the EPACK 2005 significantly amended Title II of PURPA by adding section 210(m) (providing, *inter alia*, for termination of the mandatory purchase requirement if FERC finds that the QF has nondiscriminatory access to competitive wholesale electricity markets) and section 210(n) (providing for FERC to revise its QF criteria for new qualifying cogeneration facilities).⁵² Pursuant to PURPA section 210(m), after August 8, 2005, utilities are not required to enter new contracts or obligations to purchase from QFs that are found to have nondiscriminatory access to:

A. (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

B. (i) transmission and interconnection services that are provided by a Commission-approved regional 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, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

C. wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).⁵³

51 In addition to legislative acts affecting sections 201 and 210 under PURPA Title II, Congress also has implemented several key laws affecting PURPA Title I. For example, the Energy Policy Act of 1992 amended PURPA section 111(d) to add four additional federal standards related to: (1) integrated resource planning; (2) investment in conservation and demand management; (3) investment in energy efficiency of power generation and supply; and (4) "consideration of the effects of wholesale power purchases on utility cost of capital; effects of leveraged capital structures on the reliability of wholesale power sellers; and assurance of adequate fuel supplies." See 16 U.S.C. §§ 2621(d)(7)-(10). Later, the EPACK 2005 amended PURPA section 111(d) to add five additional federal standards, including: (1) net metering; (2) fuel diversity; (3) fossil fuel generation efficiency; (4) time-based metering and communications; and (5) interconnection standards for distributed resources. *Id.* at §§ 2621(d)(11)-(15). Additionally, the Energy Independence and Security Act of 2007 amended PURPA section 111(d) to add four additional standards: (1) integrated resource planning; (2) rate design modifications to promote energy efficiency investments; (3) consideration of smart grid investments; and (4) smart grid information. *Id.* at §§ 2621(d)(16)-(19). The impact of these changes to PURPA Section 111(d) is that state energy regulators must consider whether to adopt the foregoing standards as mandatory requirements applicable to regulated electric utilities, but states are not required to adopt the standards. For further discussion of these, please refer to the *Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005* (Mar. 22, 2006), available at: <https://www.energy.gov/oe/downloads/reference-manual-and-procedures-implementation-purpa-standards-epack-2005-march-2006>, and the *Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Independence and Security Act of 2007* (Aug. 11, 2008), available at: <https://www.energy.gov/oe/downloads/reference-manual-and-procedures-implementation-purpa-standards-eisa-2007>.

52 16 U.S.C. §§ 824a-3(m), (n).

53 *Id.* at § 824a-3(m)(1).

Electric utilities are permitted to file applications with FERC for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis,⁵⁴ although QFs, state regulatory authorities, and other interested persons retain the option of filing for reinstatement of the electric utility's obligation if the conditions set forth in subparagraphs A, B, or C are no longer met.⁵⁵ Finally, after August 8, 2005, utilities are not required to enter new contracts or obligations to sell to QFs if FERC finds that competing retail electric suppliers are willing and able to sell and deliver electric energy to the QF and the utility is not required by state law to sell electric energy in its service territory.⁵⁶

PURPA section 210(n) implemented new requirements applicable to cogeneration facilities seeking to sell QF energy and capacity, providing that for facilities seeking recognition of QF status after August 8, 2005, FERC must ensure:

(i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;

(ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and

(iii) continuing progress in the development of efficient electric energy generating technology.⁵⁷

EPAAct 2005 also repealed PUHCA, thus requiring a number of corresponding changes in previously established QF ownership restrictions, affiliate transaction rules, and technology requirements for cogeneration facilities. However, holding companies and their affiliates remain subject to provisions of PUHCA 2005 requiring such companies and their affiliates to maintain and make available books, accounts, memoranda, and other records (collectively "Books and Records") that FERC determines are relevant to the costs incurred with respect to jurisdictional rates.⁵⁸

FERC's implementation of EPAAct 2005 is discussed in more detail in Subsection 4, *infra*.

54 *Id.* at § 824a-3(m)(3).

55 *Id.* at § 824a-3(m)(4).

56 *Id.* at § 824a-3(m)(5).

57 *Id.* at § 824a-3(n)(1)(A).

58 42 U.S.C. § 16452. The EPAAct 2005 directs FERC to exempt from the requirements of section 1264 of EPAAct 2005 any holding company that meets the statutory definition of one of the following entities: (1) PURPA QFs; (2) exempt wholesale generators ("EWGs"); or (3) foreign utility companies ("FUCOs"). 42 U.S.C. § 16454. EWGs are persons engaged directly, or indirectly through one or more affiliates, and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale. 18 C.F.R. § 366.1. FUCOs are companies that own or operate facilities that are not located in any state and that are used for the generation, transmission, or distribution of electric energy for sale or the distribution at retail of natural or manufactured gas for heat, light, or power, if such company: (1) derives no part of its income, directly or indirectly, from the generation, transmission, or distribution of electric energy for sale or the distribution at retail of natural or manufactured gas for heat, light, or power, within the U.S.; and (2) neither the company nor any of its subsidiary companies is a public-utility company operating in the U.S. *Id.*

4. ORDER NOS. 671 AND 688

In Order No. 671,⁵⁹ FERC incorporated the new statutory standard articulated in PURPA section 210(n) for cogeneration QFs into its regulations. FERC established a rebuttable presumption that a new cogeneration facility is used in a “productive and beneficial manner,” but stated that it will examine the use of a cogeneration facility’s thermal output to ensure that the proposed use is genuine and not merely a “sham.”⁶⁰ Where a thermal host existed prior to the development of a cogeneration facility whose thermal output will supplant the thermal source currently in use, FERC found that “it is appropriate to presume that the thermal output of such facility is productive and beneficial and to apply a very high hurdle to overcome the presumption.”⁶¹ Additionally, in determining whether the thermal output is used in a “productive and beneficial manner,” FERC declined to institute a bright line test or specific standard, but stated that it will consider factors such as whether the product produced by the thermal energy is needed and whether there is a market for the product.⁶² Similarly, FERC adopted a case-by-case approach to determining the “fundamental” use of a facility’s electrical, thermal, chemical, and mechanical output.⁶³ Nevertheless, new cogeneration facilities retain the option to self-certify as QFs.⁶⁴

Consistent with the repeal of PUHCA, FERC amended its regulations to eliminate the ownership limitations for all QFs but retained the ownership disclosure requirement in FERC’s Form No. 556.⁶⁵ FERC further revised its regulations to eliminate certain exemptions from rate regulation that were previously available to QFs.⁶⁶ In particular, FERC stated that “in light of the significant changes that have occurred in the industry since the first QF facilities were introduced and in light of the changing electric markets and resulting market power issues that have arisen in recent years, we no longer believe that it continues to be necessary or appropriate to completely exempt QFs from sections 205 and 206 of the FPA.”⁶⁷ However, FERC clarified that QFs would remain exempt from sections 205 and 206 of the FPA when a sale is made pursuant to a state regulatory authority’s implementation of PURPA, including sales made pursuant to bilateral contracts and at market-based rates.⁶⁸ In addition, to avoid creating the hardship that removal of exemptions might cause for smaller QFs, FERC provided that facilities 20 MW or smaller would remain fully exempt from sections 205 and 206 of the FPA.⁶⁹

59 *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671, 114 FERC ¶ 61,102 (2006), *order on reh’g*, Order No. 671-A, 115 FERC ¶ 61,225 (2006) (“Order No. 671”).

60 Order No. 671 at P 17.

61 *Id.*

62 *Id.*

63 *Id.* at P 50.

64 *Id.* at P 78.

65 *Id.* at PP 107, 110.

66 *Id.* at P 92.

67 *Id.* at P 96.

68 *Id.* at P 99.

69 *Id.* at P 98.



In Order No. 688,⁷⁰ FERC found that the Midwest Independent Transmission System Operator, Inc. (now re-named the Midcontinent Independent Transmission System Operator, Inc., or "MISO"), PJM Interconnection LLC ("PJM"), ISO New England Inc. ("ISO-NE"), and New York Independent System Operator, Inc. ("NYISO") administer wholesale markets meeting the criteria of PURPA section 210(m)(1)(A).⁷¹ FERC further found that the Electric Reliability Council of Texas ("ERCOT") meets the criteria of PURPA section 210(m)(1)(C).⁷² Within these five markets, FERC found that utilities are eligible to file an application with FERC seeking relief from the obligation to enter new contracts to purchase energy and capacity from interconnected QFs.⁷³ Moreover, FERC established a rebuttable presumption that QFs with a net power production capacity greater than 20 MW have nondiscriminatory access to wholesale markets, while QFs at or below 20 MW net capacity are rebuttably presumed to lack nondiscriminatory access.⁷⁴ QFs above 20 MW net capacity may rebut the presumption of nondiscriminatory access by showing that they in fact lack access.⁷⁵

FERC also concluded in Order No. 688 that the California Independent System Operator Corporation ("CAISO") and Southwest Power Pool ("SPP") are "regional transmission entities" within the meaning of the first prong of PURPA section 210(m)(1)(B), but made no findings as to the second prong for either market.⁷⁶ FERC stated that any future determination of which transmission providers may qualify as regional transmission entities within the meaning of the first prong will be made on a case-by-case basis.⁷⁷ However, FERC provided examples of relevant factors it may consider in making that determination, such as "sufficient regional scope" and "configuration of the multiple discrete transmission systems" controlled by the regional transmission entity.⁷⁸

70 *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, 117 FERC ¶ 61,078 (2006) ("Order No. 688"), *order on reh'g*, Order No. 688-A, 119 FERC ¶ 61,305 (2007) ("Order No. 688-A"), *aff'd sub nom. Am. Forest & Paper Ass'n v. FERC*, 550 F.3d 1179 (D.C. Cir. 2008).

71 Order No. 688 at P 102.

72 *Id.*

73 *Id.*

74 *Id.*

75 *Id.*

76 *Id.* at PP 158, 165.

77 *Id.* at P 166.

78 *Id.* at PP 132.



5. ORDER NO. 872

On September 19, 2019, FERC issued a Notice of Proposed Rulemaking (“NOPR”) to invite public comment concerning various revisions to its regulations implementing PURPA sections 201 and 210.⁷⁹ This issuance initiated the first major revisions to FERC’s PURPA regulations since Order Nos. 671 and 688. In the NOPR, FERC explained that it was proposing to revise the regulations “to rebalance the benefits and obligations of the Commission’s [PURPA regulations] in light of the changes in circumstances since the [PURPA regulations] were promulgated in 1980.”⁸⁰ FERC specifically emphasized the effects of the shale gas revolution and other advancements in production technology on shoring up domestic natural gas supply,

noting that the U.S. Energy Information Administration’s Annual Energy Outlook 2019 forecasts sustained growth in supply over the next 25 years.⁸¹ Further, FERC explained, developments such as state-initiated carbon-abatement programs and renewable portfolio standards, coupled with the evolution of competitive wholesale electricity markets, have significantly reduced the barriers to entry that faced small power production QFs when Order Nos. 69 and 70 were issued nearly forty years earlier.⁸² In addition, FERC highlighted record evidence gathered from a 2016 technical conference⁸³ suggesting that “overestimations of avoided cost have not been balanced by underestimations” and that energy rates for independently-owned generation resources need not be fixed in order to obtain financing.⁸⁴

79 Notice of Proposed Rulemaking, *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Docket Nos. RM19-15-000 and AD16-16-000, 168 FERC ¶ 61,184 (Sept. 19, 2019) (“PURPA NOPR”).

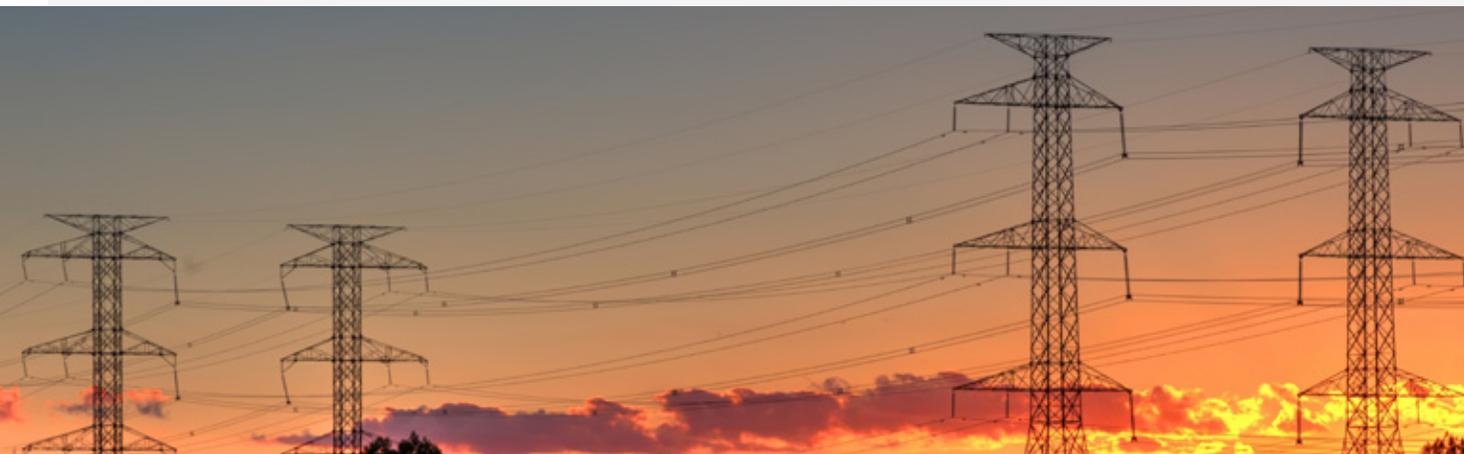
80 PURPA NOPR at P 4.

81 *Id.* at P 19.

82 *Id.* at PP 20-25. FERC acknowledged that cogeneration has not achieved comparable levels of market penetration, and thus remains more dependent on PURPA.

83 The technical conference, conducted in Docket No. AD16-16-000, covered such issues as: (1) various methods for calculating avoided cost; (2) the obligation to purchase pursuant to a LEO; (3) application of the one-mile rule; and (4) the rebuttable presumption FERC has adopted under PURPA section 210(m) that QFs 20 MW and below do not have nondiscriminatory access to competitive organized wholesale markets. See Supplemental Notice of Technical Conference, *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Docket No. AD16-16-000 (May 9, 2016). The NOPR stated that in addition to the oral presentations made at the conference, FERC received numerous “helpful” written comments that informed the revisions proposed in the NOPR. PURPA NOPR at P 28. Accordingly, the NOPR explicitly incorporated the technical conference record into FERC’s rulemaking proceeding. *Id.*

84 PURPA NOPR at P 30.



In a Final Rule issued July 16, 2020, Order No. 872,⁸⁵ FERC adopted a significant series of reforms to address these industry developments. Under Order No. 872, state regulatory authorities and nonregulated electric utilities were given additional flexibility relating to the determination of avoided costs:

- State regulatory authorities and nonregulated electric utilities may "require that energy rates (but not capacity rates) in QF power sales contracts and other [legally enforceable obligations ("LEOs")] vary in accordance with changes in the purchasing electric utility's as-available avoided costs at the time the energy is delivered."⁸⁶
- State regulatory authorities and nonregulated electric utilities may continue to authorize the use of fixed energy rates, but these entities may determine that the fixed energy rate will be "based on projected energy prices during the term of a QF's contract."⁸⁷
- FERC established a rebuttal presumption that the "[locational marginal price ("LMP")] established in the organized electric markets . . . represents the as-available avoided costs of electric utilities located in these markets. So long as this presumption is not rebutted, a state [or nonregulated electric utility] can at its option establish as-available energy avoided cost rates for QFs selling to such electric utilities at the LMP."⁸⁸
- With respect to QFs selling to electric utilities located outside of the organized electric markets, FERC held that state regulatory authorities and nonregulated electric utilities have the option to set as-available energy avoided cost rates 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 [or nonregulated electric utilities] first determine that such prices represent the purchasing electric utilities' avoided costs."⁸⁹
- FERC acknowledged that state regulatory authorities and nonregulated electric utilities continue to have "the flexibility to set energy and capacity rates pursuant to a competitive solicitation process conducted pursuant to transparent and non-discriminatory procedures,"⁹⁰ and issued additional guidance regarding the requirements for such procedures.



85 *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 ("Order No. 872"), *order on clarification, in part*, Order No. 872-A, 173 FERC ¶ 61,158 (2020) ("Order No. 872-A"). Petitions for review of these orders have been filed. See *infra* at n.98.

86 Order No. 872 at P 57 (internal citations omitted).

87 *Id.* at P 58.

88 *Id.* at P 59 (internal citations omitted).

89 *Id.*

90 *Id.* at P 60. Such procedures must be consistent with FERC's *Allegheny* standard, described in Order No. 872 at P 429 and summarized in Section II.D.6 of this Manual.

In addition to its emphasis on pricing reforms, FERC Order No. 872 addressed other elements of FERC policy under PURPA. Specifically, FERC

- Modified the “one-mile rule” used to determine if “generation facilities are considered to be at the same site for purposes of determining qualification as a qualifying small power production facility” by allowing electric utilities, state regulatory authorities, and other interested parties to show that affiliated small power production facilities that use the same energy resource and are more than one mile apart and less than 10 miles apart actually are at the same site (with distances one mile or less apart still irrebuttably at the same site, and distances 10 miles or more apart irrebuttably at separate sites).⁹¹
- Revised its procedures 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.”⁹²
- “Update[d] the rebuttable presumption for small power production facilities (but not cogeneration facilities) that have nondiscriminatory access to certain markets from 20 MW to 5 MW and . . . revise[d] the regulations to include examples of factors . . . that QFs may argue show that they lack nondiscriminatory access to such markets.”⁹³

91 *Id.* at P 62.

92 *Id.* at P 63.

93 *Id.* at P 64.

94 *Id.* at P 65.

95 Order No. 872-A at P 3.

96 *Id.*

- Clarified “that a QF must demonstrate commercial viability and financial commitment to construct its facility pursuant to objective and reasonable state-determined criteria before the QF is entitled to a contract or LEO.”⁹⁴

On November 19, 2020, FERC issued Order No. 872-A generally denying rehearing and clarifying the discussion in Order No. 872.⁹⁵ These limited clarifications addressed: (1) states’ use of tiered avoided cost pricing; (2) states’ use of variable energy rates in QF contracts and availability of utility avoided cost data; (3) the role of independent entities overseeing competitive solicitations; (4) the circumstances under which a small power production QF needs to recertify its QF status; (5) application of the rebuttable presumption of separate sites for the purpose of determining the power production capacity of small power production facilities; and (6) the PURPA section 210(m) rebuttable presumption of nondiscriminatory access to markets and the accompanying regulatory text.⁹⁶



Given the nature of the changes promulgated in Order No. 872 and upheld by FERC in Order No. 872-A, the revised regulations are expected to be subject to protracted litigation and appeal.⁹⁷ Multiple petitions for review of Order Nos. 872 and 872-A are pending in the U.S. Court of Appeals for the Ninth Circuit.⁹⁸

6. FERC REGULATIONS

FERC's current regulations under PURPA sections 201 and 210 with regard to cogeneration and small power production facilities are codified at 18 C.F.R. Part 292.

Subpart A contains general provisions, including applicable definitions.

Subpart B contains QF regulations regarding general requirements and criteria for qualification, as well as procedures for obtaining QF status. This Subpart also contains provisions governing hydroelectric small power production facilities.

Subpart C concerns arrangements between electric utilities and QFs, including general obligations as well as provisions on rates for both sale and purchase, interconnection costs, system emergencies, and standards for operating reliability. This Subpart also contains provisions and procedures for termination and reinstatement of PURPA obligations, as well as existing rights and remedies.

Subpart D implements certain reporting requirements, subject to waiver by FERC.

Subpart E is merely reserved for future use by FERC.

Subpart F contains provisions exempting QFs from certain requirements under the FPA and PUHCA 2005, as well as most state laws and regulations.

⁹⁷ Analysts have noted widespread criticism of Order No. 872 among clean energy and environmental advocacy groups. See, e.g., William Driscoll, *SEIA Challenges FERC's PURPA Rules*, PV MAGAZINE (Aug. 25, 2020), <https://pv-magazine-usa.com/2020/08/25/seia-challenges-fercs-purpa-rules/>; Jeff John, *FERC's New PURPA Rule Undermines Clean Energy Projects, Advocates Say*, GREENTECH MEDIA (July 16, 2020), <https://www.greentechmedia.com/articles/read/fercs-new-purpa-rule-undermines-clean-energy-projects-advocates-say>; Peter Maloney, *Is PURPA Done? New Bill Takes Aim at Law's Mandatory Purchase Obligation*, UTILITY DIVE (Feb. 12, 2018), <https://www.utilitydive.com/news/is-purpa-done-new-bill-takes-aim-at-laws-mandatory-purchase-obligation/516721/>.

⁹⁸ See Ninth Circuit Case Nos. 20-72788, 20-73375, 21-70083, and 21-70113 (consolidated).

PURPA Overview – Key Requirements

Section 210 of PURPA contains a number of significant provisions for electric utilities. Codified at 16 U.S.C. § 824a-3, and titled "Cogeneration and Small Power Production," section 210 includes the following key requirements:

Section 210(a)	<ul style="list-style-type: none"> • FERC must implement rules encouraging the development of "cogeneration" and "small power production" facilities <ul style="list-style-type: none"> ▪ The rules include requirements for electric utilities to offer to: <ul style="list-style-type: none"> - Sell electric energy to qualifying cogeneration and qualifying small power production facilities; and - Purchase electric energy from such facilities ▪ FERC's regulations implemented pursuant to PURPA are found in 18 C.F.R. Part 292
Section 210(b)	<ul style="list-style-type: none"> • The rates paid by utilities for the energy and capacity purchased from QFs should be just and reasonable to the utility's electric consumers and in the public interest, and should not discriminate against QFs • FERC may not promulgate rules providing for rates that exceed the incremental cost to the electric utility of alternative electric energy, generally referred to as the electric utility's "avoided cost"
Section 210(c)	<ul style="list-style-type: none"> • The rates for sales by utilities to QFs shall be just and reasonable and in the public interest and shall not discriminate against QFs
Section 210(f)	<ul style="list-style-type: none"> • State regulatory authorities (such as public utility commissions) and nonregulated electric utilities (such as rural cooperatives and municipalities not regulated by state authority) must review and implement any rule or rule revision that is promulgated by FERC pursuant to PURPA sections 201 and 210 within one year of issuance
Section 210(g)	<ul style="list-style-type: none"> • For judicial review and enforcement - <ul style="list-style-type: none"> ▪ The proper forum for interpretation or implementation of a PURPA QF regulation is the state regulatory authority and/or nonregulated electric utility ▪ Normal state appellate procedures apply if a party wants to challenge a state or a local regulatory authority's decision or interpretation in implementing a PURPA QF regulation
Section 210(h)	<ul style="list-style-type: none"> • Any PURPA rule implemented by FERC itself shall be treated as a rule enforceable under the Federal Power Act and thus enforceable by FERC in federal district court • If FERC declines to bring an action in federal court, the utility or QF may file its own enforcement action against the state regulatory authority in federal district court
Section 210(m)	<ul style="list-style-type: none"> • Utilities may seek termination of the mandatory purchase requirement if FERC finds that the QF has nondiscriminatory access to competitive wholesale electricity markets for long-term sales of capacity and electric energy
16 U.S.C. § 2602, Definitions	<ul style="list-style-type: none"> • PURPA defines the term "electric utility" to include companies and federal and state agencies that sell electric energy. Electric utilities include: <ul style="list-style-type: none"> ▪ Investor-owned electric companies ▪ Public power utilities ▪ Electric cooperatives



E. COOPERATIVE FEDERALISM—THE ROLE OF STATES AND NONREGULATED ELECTRIC UTILITIES IN IMPLEMENTING PURPA

PURPA and FERC's regulations impose significant responsibility on "state regulatory authorities"⁹⁹ and "nonregulated electric utilities"¹⁰⁰ for implementation of QF policies. As a threshold matter, PURPA section 210(f) provides that state regulatory authorities (such as public utility commissions) and nonregulated electric utilities (such as rural cooperatives and municipalities not regulated by state authority) must review and implement any rule or rule revision that is promulgated by FERC pursuant to PURPA sections 201 and 210 within one year of issuance.¹⁰¹ In turn, FERC's regulations delegate responsibility to state regulatory authorities and nonregulated electric utilities for determining avoided cost rates for individual utilities, though such determination must at least consider a number of prescribed factors.¹⁰² This grant of authority expands the traditional scope of state jurisdiction over rate regulation, since, by definition, QF sales occur at wholesale and would normally fall under FERC's exclusive purview.¹⁰³

Additionally, FERC's regulations delegate responsibility to state regulatory authorities

and nonregulated electric utilities for determining just and reasonable rates for supplemental services,¹⁰⁴ calculating interconnection fees,¹⁰⁵ and establishing standards for operating reliability.¹⁰⁶ It should be noted, however, that PURPA tempers its grant of state authority in these areas by constricting state authority in other areas—namely, by permitting FERC to exempt QFs from state utility holding company acts and other provisions affecting the financial organization of QFs.¹⁰⁷

Title II of PURPA contains a similarly elaborate enforcement scheme with both federal and state components, including provisions for state judicial review in cases originating under state law. PURPA section 210(g) provides for: (1) state court review of state regulatory authorities' orders implementing PURPA; and (2) state court adjudication of actions to enforce state regulatory authorities' PURPA rules.¹⁰⁸ However, under PURPA section 210(h)(1), any PURPA rule implemented by FERC itself shall be treated as a rule enforceable under the FPA and thus enforceable by FERC in federal district

99 The term "state regulatory authority" means "any State agency which has ratemaking authority with respect to the sale of electric energy by any electric utility (other than such State agency), and in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority, such term means the Tennessee Valley Authority." 16 U.S.C. § 2602(17).

100 The term "nonregulated electric utility" means "any electric utility other than a State regulated electric utility." 16 U.S.C. § 2602(9). PURPA further defines "State regulated electric utility" as "any electric utility with respect to which a State regulatory authority has ratemaking authority." *Id.* at § 2602(18).

101 16 U.S.C. § 824a-3(f).

102 18 C.F.R. § 292.304.

103 Under the FPA, interstate transmission and wholesale sales of electric energy are FERC-jurisdictional, whereas state commissions retain authority over local distribution and retail sales. See 16 U.S.C. § 824(b)(1). Wholesale sales are defined as "sale of electric energy to any person for resale." *Id.* at § 824(d).

104 18 C.F.R. § 292.305.

105 *Id.* at § 292.306.

106 *Id.* at § 292.308.

107 16 U.S.C. § 824a-3(e).

108 *Id.* at § 824a-3(g).

court.¹⁰⁹ Accordingly, PURPA section 210(h)(2)(A) provides that FERC may bring an enforcement action against a state regulatory authority in federal district court, and PURPA section 210(h)(2)(B) allows any utility or QF to file a petition with FERC seeking enforcement of PURPA section 210(f) (described above).¹¹⁰ Then, if FERC declines to bring such an action, the utility or QF may file its own enforcement action against the state regulatory authority in federal district court.¹¹¹

In *FERC v. Mississippi*, the Supreme Court rejected allegations by the State of Mississippi and the Mississippi Public Service Commission that PURPA section 210 exceeded Congressional power under the Commerce Clause of the U.S. Constitution and invaded state sovereignty in violation of the Tenth Amendment.¹¹² With regard to the Commerce Clause, the Court held that generation and supply of electric power plainly

implicate interstate commerce given that utilities sell to retail customers power that is generated beyond state borders and offer reciprocal services to utilities in other states.¹¹³ Moreover, Congressional findings related to the need to promote cogeneration and small power production in the interests of energy efficiency and fuel diversity provided “ample support” that Congress acted with a rational basis.¹¹⁴

With regard to the Tenth Amendment, the Court opined that PURPA “establishes a program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs.”¹¹⁵ The Court acknowledged that PURPA section 210 required each state regulatory authority to implement rules requiring electric utilities to purchase electric power from and sell it to

109 See *id.* at § 824a-3(h)(1); 16 U.S.C. § 825m.

110 See 16 U.S.C. § 824a-3(h)(2)(B).

111 *Id.*

112 456 U.S. 742 (1982).

113 *Id.* at 757.

114 *Id.* at 755-756.

115 *Id.* at 767 (quoting *Hodel v. Va. Surface and Reclamation Ass'n, Inc.*, 452 U.S. 264, 289 (1981)).



QFs.¹¹⁶ However, the Court noted that FERC's regulations provided that state regulatory authorities may implement this by, among other things, "an undertaking to resolve disputes between qualifying facilities and electric utilities arising under [PURPA]."¹¹⁷ The Court thus found that PURPA merely required state regulatory authorities to adjudicate disputes under the statute and did not "commandeer" state legislative processes by directly compelling states to enact and enforce a regulatory program.¹¹⁸ Further, the Court found that "[i]nsofar as [PURPA section 210] authorizes FERC to exempt qualified power facilities from State laws and regulations, it does nothing more than pre-empt conflicting state enactments in the traditional way."¹¹⁹ Congress and FERC traditionally may displace state laws that conflict with federal programs, so the Court ultimately held that requiring state regulatory authorities to administer their own regulatory programs within limits established by federal minimum standards was not improper.¹²⁰

More recently, courts have grappled with the extent of federal jurisdiction under PURPA as well as the level of deference owed to state agencies' implementation of the federal PURPA regulations.¹²¹ Because *FERC v. Mississippi* characterized the statute as allowing states to implement PURPA simply by adjudicating disputes arising under its provisions (while giving states the option to implement PURPA via rulemaking "or by taking any other action reasonably designed to give effect to FERC's rules"),¹²² some have argued that the statute's grant of federal jurisdiction should be interpreted narrowly.¹²³ Courts have also grappled with questions relating to PURPA's preemptive scope, especially with regard to state-created regulatory mechanisms to promote alternative energy use such as renewable energy credits and other incentives or subsidies.¹²⁴ In addition, states increasingly have sought to revisit historic implementation of local rules pertaining to bilateral contract terms and the criteria for establishing a LEO—oftentimes triggering petitions for enforcement filed

116 *Id.* at 759-60.

117 *Id.* at 760 (citing 18 C.F.R. § 292.401(a)).

118 *Id.* at 760, 764-65 (citing *Hodel*, 452 U.S. at 288).

119 *Id.* at 760 (citations omitted).

120 *Id.* at 767-69.

121 See, e.g., *Exelon Wind 1, L.L.C. v. Nelson*, 766 F.3d 380, 393-95 (5th Cir. 2014) (rejecting arguments that federal courts only have jurisdiction to hear claims asserting that the state regulatory authority has failed to open its doors to adjudicate disputes under PURPA when it is simultaneously hearing similar state lawsuits, and applying a deferential standard in review of the Texas Public Utility Commission's implementation of PURPA); see also *Idaho Power Co. v. Idaho Pub. Utils. Comm'n*, 316 P.3d 1278 (Idaho 2013).

122 *Mississippi*, 456 U.S. at 751.

123 *Exelon Wind 1*, 766 F.3d at 393-94 ("The PUC insists that we should read PURPA's jurisdictional grant [] narrowly, based on the Supreme Court's reasoning in *FERC v. Mississippi*. Under the PUC's view, federal courts only have jurisdiction to hear claims asserting that the PUC has failed to open its doors to adjudicate disputes under PURPA when it is simultaneously hearing similar state lawsuits. While this reading of PURPA's jurisdiction provisions may be possible, it is not compelled by the Supreme Court's decision in *FERC v. Mississippi*, and would conflict with our own prior interpretation of the scope of PURPA's jurisdictional grant!") (internal citations omitted).

124 See, e.g., *Arippa v. Pa. Pub. Util. Comm'n.*, 966 A.2d 1204, 1208-11 (Pa. Commw. Ct. 2009) (upholding the Pennsylvania Public Utility Commission in giving alternative energy credits to the electric distribution companies and holding that PURPA does not preempt the state's assignment of RECs); *In re Ownership of Renewable Energy Certificates*, 913 A.2d 825, 831 (N.J. Super. Ct. App. Div. 2007) (same result). *But see S. Cal. Edison Co. v. Pub. Utils. Comm'n*, 101 Cal. App. 4th 384, 396-99 (Cal. Ct. App. 2002) (holding that PURPA preempted the California Public Utilities Commission from setting a minimum transmission loss factor for PURPA QFs that relied on renewable resources for their fuel sources).

at FERC by QFs seeking injunctive or other relief. In one notable example, FERC filed a complaint in the U.S. District Court for Idaho against the Idaho Public Utilities Commission ("Idaho PUC") in response to petitions for enforcement filed by multiple QFs alleging that Idaho PUC had improperly rejected power purchase agreements ("PPAs") under PURPA.¹²⁵ Specifically, the complaints involved the Idaho PUC's decision to temporarily reduce its size cap for facilities eligible to receive standard published avoided cost rates, and its subsequent decision that agreements must have been executed prior to the effective date of the temporary rule in order for the reduced cap to apply.¹²⁶ The action was ultimately dismissed by the district court in light of a Memorandum of Agreement ("MOA") reached between FERC and the Idaho PUC. In the MOA, FERC and the Idaho PUC acknowledged that:

PURPA establishes a program of cooperative federalism. The FERC is required to issue regulations to give effect to federal policy, as set by Congress in the statute, to encourage small power production development. State regulatory authorities, such as the Idaho PUC, are responsible for implementing the FERC's regulations, and may do so in a manner that accommodates local conditions and concerns so long as the implementation is consistent with PURPA and the FERC's PURPA regulations.¹²⁷

The Idaho PUC additionally acknowledged that a LEO may be incurred prior to formal memorialization of a contract in writing, consistent with FERC's regulations, and the parties ultimately agreed to submit to the district court a joint stipulation for voluntary dismissal.¹²⁸

Thus, as recognized by the Supreme Court and by FERC itself, PURPA reflects a model of cooperative federalism wherein state public utility commissions (or other local implementing authorities) are delegated responsibility to establish and maintain minimum standards yet retain significant leeway to harmonize local policies within the federal framework. These jurisdictional boundaries are not formalistic; rather, recent regulatory and case law developments suggest an expanding zone of influence for the states.¹²⁹ Some of these developments are explored in Section II.G., *infra*.

¹²⁵ *FERC v. Idaho Pub. Utils. Comm'n*, No. 1:13-CV-00141-EJL, 2013 WL 6229368, at *3-7 (D. Idaho Dec. 2, 2013).

¹²⁶ *Id.* at *4.

¹²⁷ Memorandum of Agreement Between the Federal Energy Regulatory Commission and the Idaho Public Utility Commission (Dec. 24, 2013).

¹²⁸ *Id.*

¹²⁹ See, e.g., *Exelon Wind 1, L.L.C. v. Nelson*, 766 F.3d 380 (5th Cir. 2014); *Idaho Power Co. v. Idaho Pub. Utils. Comm'n*, 316 P.3d 1278 (Idaho 2013).

FERC versus State Regulatory Authorities and Nonregulated Electric Utility Jurisdiction Who Does What?



FERC	State Regulatory Authorities and Nonregulated Electric Utilities
<p>Implements regulations as directed in the PURPA statute</p>	<p>Review and implement FERC's regulations</p> <p>Note – State regulatory authorities and nonregulated electric utilities may elect to act by rule or through individual proceedings</p>
<p>Adopts policies – through rulemakings or individual proceedings – that interpret and explain the PURPA statute and FERC's own implementing regulations</p> <p>Example: the "one mile" rule</p>	<p>Address, through rules or individual proceedings, policies where FERC has directly or impliedly delegated responsibility to act, including</p> <ul style="list-style-type: none"> • to establish avoided cost rates or ratemaking methodologies • requirements regarding contract duration for PURPA power purchases • development of forecasting methodologies for use in determining avoided costs • adoption of criteria for legally enforceable obligations • administration of competitive solicitation processes for PURPA procurement
<p>Addresses "implementation disputes" – claims that a state regulatory authority or a nonregulated electric utility has failed to "implement" PURPA appropriately</p>	<p>State courts address "as applied" disputes – claims that an electric utility's application of PURPA to one or more QFs does not comply with PURPA or FERC's regulations</p>
<p>Has jurisdiction over the interconnection and transmission of energy in interstate commerce</p>	<p>Has jurisdiction over interconnection and allocation of interconnection costs when the interconnected utility is purchasing all of a QF's output pursuant to PURPA</p>



II. Key Topics — Review and Discussion of Legal Authorities and Issues

A. ELECTRIC UTILITIES AND JURISDICTIONAL CONSIDERATIONS

Unlike most provisions of the FPA, which frames applicability and FERC jurisdiction in terms of “public utilities,” PURPA section 210 applies principally to a different category of entities—“electric utilities.” For purposes of the “must purchase” and other obligations to QFs under PURPA, electric utilities include persons and state and federal agencies that “sell[] electric energy.”¹³⁰ This includes entities that are normally exempt from FERC jurisdiction under Part II of the FPA, such as municipal utilities and many rural electric cooperatives.¹³¹

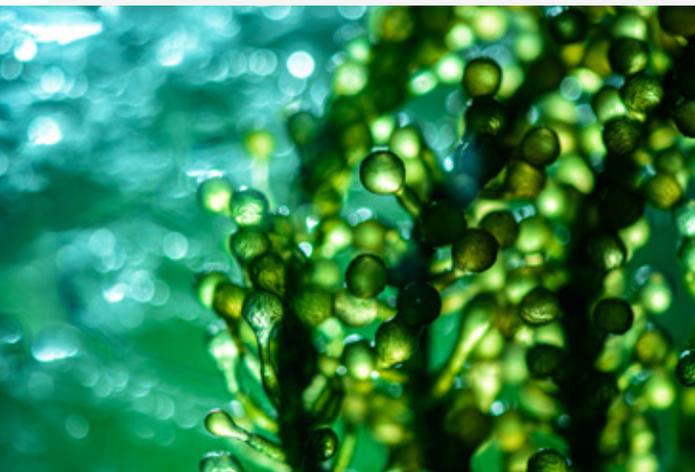
These entities may in fact be “nonregulated electric utilities” under PURPA,¹³² in which case they carry both the obligations to implement FERC’s PURPA regulations in their respective capacities as regulators, but also the obligations of electric utilities to purchase QF output and to comply with the other obligations of electric utilities.



¹³⁰ 16 U.S.C. § 2602(4).

¹³¹ 16 U.S.C. §§ 824(f), (e).

¹³² Municipal utilities and rural electric cooperatives may be “nonregulated electric utilities,” see *supra* at n.100. Generally, when FERC references the obligations of states in the context of its PURPA regulations and policies, it is usually referring to the obligations of nonregulated electric utilities as well. See, e.g., Order No. 872 at P 94. As has been noted by FERC, “[n]onregulated electric utilities implement the requirements of PURPA with respect to themselves.” *Id.* at P 96 & n.141





B. QUALIFYING FACILITIES—CRITERIA AND REQUIREMENTS

There are two categories of QFs, small power production facilities and cogeneration facilities.¹³³ A small power production facility is a facility that is an eligible solar, wind, waste or geothermal facility;¹³⁴ or a facility that produces electric energy solely by the use, as a primary energy source,¹³⁵ of biomass,¹³⁶ waste,¹³⁷ renewable resources, geothermal resources, or any combination thereof; and has a power production capacity that,

together with any other facilities located at the same site (as determined by FERC), is not greater than 80 MW.¹³⁸ A cogeneration facility is generally defined as a facility that produces electric energy, and steam or forms of useful energy (such as heat), that are used for industrial, commercial, heating or cooling purposes.¹³⁹ A QF may include transmission lines and interconnection equipment where such lines and equipment facilitate the delivery

¹³³ 16 U.S.C. §§ 796(17)(C), (18)(B); see also 18 C.F.R. § 292.101(b)(1).

¹³⁴ An “eligible solar, wind, waste or geothermal facility” is one “which produces electric energy solely by the use, as a primary energy source, of solar energy, wind energy, waste resources or geothermal resources . . .” 16 U.S.C. § 796(17)(E).

¹³⁵ “Primary energy source” means “the fuel or fuels used for the generation of electric energy,” except that “primary energy source” does not include, as determined under rules prescribed by FERC (1) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses; and (2) the minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages and emergencies directly affecting the public health, safety, or welfare, which would result from electric power outages. 16 U.S.C. § 796(17)(B).

¹³⁶ “Biomass” is “any organic material not derived from fossil fuels.” 18 C.F.R. § 292.202(a).

¹³⁷ “Waste” is defined as an energy input that includes but is not limited to specific materials that FERC previously has approved as waste, or “any energy input that has little or no current commercial value and exists in the absence of the qualifying facility industry.” 18 C.F.R. § 292.202(b).

¹³⁸ 16 U.S.C. § 796(17)(A).

¹³⁹ *Id.* at § 796(18)(A); see also 18 C.F.R. § 292.202(c).

of power to or from a QF.¹⁴⁰ PURPA provides these general definitions and requires FERC to prescribe rules to encourage small power production facilities and cogeneration.¹⁴¹ FERC's criteria and requirements for qualifying small power production facilities and qualifying cogeneration facilities are discussed below.

1. CRITERIA AND REQUIREMENTS FOR QUALIFYING SMALL POWER PRODUCTION FACILITIES

As discussed below, a small power production facility is a QF if it (1) meets the maximum size requirement; (2) meets the fuel use criteria; and (3) unless exempted, has filed with FERC a notice of self-certification or an application for Commission certification that has been granted.¹⁴²

a) Maximum size requirement

PURPA and FERC's implementing regulations limit small power production QFs to a "power production capacity" of 80 MW at the same site.¹⁴³ FERC's regulations state, in part, that "the power production capacity of a facility for which qualification is sought, 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, may not exceed 80 megawatts."¹⁴⁴

i. Determining "power production capacity"

Neither PURPA nor FERC's implementing regulations provide guidance on how to compute the 80 MW maximum size limit for qualifying facilities. Therefore, FERC has established the method for such measurement through individual proceedings. In *Occidental Geothermal, Inc.*,¹⁴⁵ FERC addressed the issue of how to measure power production capacity for a facility that would use geothermal steam as its primary energy source.

FERC noted that the Conference Report accompanying PURPA indicates that the power production capacity of a facility is its "rated capacity."¹⁴⁶ FERC adopted the following standard for determining the power production capacity of a facility:

140 The FERC Regulations provide that a QF may include transmission lines and other interconnection equipment, if: "(A) [s]uch lines and equipment are used to supply power output to directly and indirectly interconnected electric utilities, and to end users, including thermal hosts, in accordance with state law; or (B) [s]uch lines and equipment are used to transmit supplementary, standby, maintenance and backup power to the qualifying facility, including its thermal host meeting the criteria set forth in *Union Carbide Corporation*, 48 FERC ¶ 61,130, *reh'g denied*, 49 FERC ¶ 61,209 (1989), *aff'd sub nom.*, *Gulf States Utilities Company v. FERC*, 922 F.2d 873 (D.C. Cir. 1991); or (C) [i]f such lines and equipment are used to transmit power from other qualifying facilities or to transmit standby, maintenance, supplementary and backup power to other qualifying facilities." 18 C.F.R. § 292.101(b)(1)(i).

141 See 16 U.S.C. § 824a-3; 16 U.S.C. §§ 796(17)(C), (18)(B).

142 18 C.F.R. § 292.203(a).

143 16 U.S.C. §§ 796(17)(A)(ii), (17)(C).

144 18 C.F.R. § 292.204(a)(1). There is an exception for an eligible solar, wind, waste, or geothermal facility if such facility submitted to FERC before December 31, 1994 an application for QF certification or a notice of certification, and construction of the facility commenced not later than December 31, 1999, or if not, reasonable diligence is exercised toward completion of the facility. Such facilities have no maximum size and the power production capacity of such facilities is excluded from consideration in determining the size of other small power production facilities less than ten miles from such facilities. *Id.* at § 292.204(a)(4).

145 17 FERC ¶ 61,231 (1981) ("*Occidental*").

146 *Id.* at 61,444.

The Commission will consider the “power production capacity” of a facility to be the maximum net output of the facility which can be safely and reliably achieved under the most favorable operating conditions likely to occur over a period of several years. *The net output of the facility is its send out after subtraction of the power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, and exciters) and for other essential electricity uses in the facility from the gross generator output.*

The occasional occurrence of power outputs of more than 80 megawatts does not necessarily indicate a power production capacity exceeding the qualifying limit if the occurrences are rare, such as once or twice in a five year period, and if they are clearly attributable to unusual circumstances. Thus, an applicant’s statement that under certain circumstances the send out may exceed 80 megawatts does not in itself prevent qualification.

An applicant’s statement that the power production capacity of the facility will not exceed 80 megawatts is accepted as determinative, in the absence of evidence to the contrary, consistent with the principles discussed above.¹⁴⁷

FERC then referenced the applicant’s representation in *Occidental* that the net power production capacity of the facility would not normally exceed 80 MW although it could do so under certain circumstances, such as when favorable climatic conditions reducing auxiliary load on the power plant cause an input of more than 80 MW into the grid.¹⁴⁸ FERC determined that “this type of increase or decrease in power capacity for limited periods, as a result of circumstances beyond the control of the Applicant,” does not violate FERC’s 80 MW size limit regulation.¹⁴⁹

Recently, FERC rejected and then reaffirmed the *Occidental* precedent for determining power production capacity for purposes of the 80 MW QF size limit. In *Broadview Solar, LLC*,¹⁵⁰ FERC addressed certification of a combined solar photovoltaic (“PV”) and battery storage facility. The facility at issue consisted of a 160 MW solar array and 50 MW battery storage system. The amount of power that could be delivered would be limited by inverters.¹⁵¹ The applicant relied on FERC precedent, including *Occidental*, in arguing that its solar array and battery storage system should be viewed as a combined output, because both the solar array and the battery

147 *Id.* (emphasis added).

148 *Id.*

149 *Id.*

150 172 FERC ¶ 61,194 (2020) (“*Broadview I*”).

151 *Id.* at P 2.

storage system are behind the inverters and the inverters can convert no more than 82.5 MW from the facility.¹⁵²

In *Broadview I*, FERC rejected the applicant's arguments. FERC noted that its precedent sometimes allowed facilities with power production capacities in excess of 80 MW to be certified as QFs when the net output was no more than 80 MW and also sometimes allowed intermittent net outputs slightly in excess of 80 MW. However, FERC found in *Broadview* that "there is a significant difference between (i) design capabilities that may incidentally or occasionally cross PURPA's 80 MW threshold due to certain components or variances, such as fuel or ambient temperatures and (ii) a facility purposefully designed with a 160 MW solar array."¹⁵³ FERC concluded that the "send out" analysis applied in *Occidental* is inconsistent with the 80 MW "power production capacity" limitation in PURPA for small power production QFs.¹⁵⁴ Based on this new analysis, FERC determined that *Broadview's* facility exceeded the 80 MW statutory limit for "power production capacity" and the limit could not be met by relying on inverters as a limiting element on a QF's output.¹⁵⁵

Broadview I applied for only several months. On rehearing, FERC reversed *Broadview I* and reinstated the "send-out" analysis that determines a facility's power production capacity based on the electricity that it can actually deliver to the interconnected utility.¹⁵⁶

ii. The "one-mile" rule

For purposes of the 80 MW QF size limitation, FERC determines whether small power production facilities are located at the "same site" based on what is referred to as the "one-mile rule." As initially adopted by FERC, the one-mile rule stated that "facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation."¹⁵⁷ The distance between facilities is measured from the electrical generating equipment of a facility.¹⁵⁸

Since the adoption of the one-mile rule, FERC has recognized challenges with its implementation. FERC acknowledged "the difficulty in prescribing site criteria for purposes of calculation of the size of the facility."¹⁵⁹ For example, in some instances, developers of small power production facilities circumvented the one-mile rule by siting their small power production facilities that use the same energy resource just over one mile apart in order to qualify as small power production facilities.¹⁶⁰ There was also ambiguity in the requirement that the one-mile limit be

¹⁵² *Id.* at P 7.

¹⁵³ *Id.* at P 21.

¹⁵⁴ *Id.* at PP 22-23 (citations omitted).

¹⁵⁵ *Id.* at P 25.

¹⁵⁶ *Broadview Solar, LLC*, 174 FERC ¶ 61,199 (2021).

¹⁵⁷ Order No. 70, 45 FR at 17972.

¹⁵⁸ *Id.*

¹⁵⁹ *Id.* at 17965.

¹⁶⁰ See, e.g., *N. Laramie Range All., et al.*, 138 FERC ¶ 61,171, *reh'g denied*, 139 FERC ¶ 61,190 (2012) (FERC denied a petition for declaratory order requesting that it revoke the QF status of two wind generation facilities. The two facilities were located more than one mile apart. However, the Petitioner argued FERC should treat them as a single facility with a total net capacity in excess

measured as the distance between “electrical generating equipment” because for some generating facilities, the electrical generating equipment could include equipment such as wind turbines or solar facilities that are spread over a geographic area. The FERC regulations did not specify how to measure the distance between such facilities, or how to measure the distance between facilities that have multiple sets of “electrical generating equipment.”¹⁶¹

iii. Reforms adopted in Order No. 872

In Order No. 872, FERC determined that “since the establishment of the one-mile rule in the [PURPA regulations] in 1980, the development of large numbers of affiliated renewable resource facilities requires a revision of the one-mile rule.”¹⁶² FERC reiterated that its determination whether or not a small power production facility exceeds the 80 MW QF power production capacity limit should continue to be based on whether the subject facility and nearby affiliated QFs are at the same site or separate sites, not whether the two facilities are a single facility.¹⁶³ FERC also found that for purposes of determining whether affiliated facilities are at the same site or separate sites, only affiliated small power production QFs are relevant to the determination.¹⁶⁴

Order No. 872 also adopted several reforms to the one-mile rule. For purposes of the 80 MW small power production QF size limitation, FERC found that providing set geographic distances for determining whether facilities are located at the same site “will limit unnecessary disputes over whether facilities are at the same site, and therefore [FERC] must choose reasonable distances at which small power production facilities will be considered irrebuttably at the same site or irrebuttably at separate sites.”¹⁶⁵ Accordingly, Order No. 872 adopted the following presumptions regarding the distance between facilities for purposes of determining whether facilities are located at the “same site”:

- For affiliated small power production facilities using the same energy resource, one mile or less is a reasonable distance to treat such facilities as irrebuttably at the same site.¹⁶⁶
- For affiliated small power production facilities that use the same energy resource but are ten miles or more apart, it is reasonable to treat them as irrebuttably at separate sites.¹⁶⁷
- For affiliated small power production facilities using the same energy resource that are more than one mile but less than ten miles apart, the distinction between the same site or separate sites is not clear, so it is reasonable to allow parties to provide evidence to rebut the presumption that such facilities are considered to be separate QFs.¹⁶⁸

of the 80 MW small power production QF limit, because the facility owner was gaming the one-mile rule. Among other things, FERC rejected arguments that the one-mile rule is only a “rebuttable presumption,” and that the FERC has indicated that it would disregard the one-mile rule where there is evidence of gaming.)

161 PURPA NOPR at P 99.

162 Order No. 872 at P 472.

163 *Id.* at P 477.

164 *Id.* at P 478.

165 *Id.* at P 491.

166 *Id.*

167 *Id.*

168 *Id.* at PP 490-91.

FERC concluded that establishing these distances, particularly the rebuttable presumption of separate sites for affiliated small power production facilities more than one mile but less than ten miles apart, “better allows the Commission to address the evolving shape and configuration of resources, such as modular solar or wind power plants, that are being developed as QFs, and provides for improved administration of PURPA.”¹⁶⁹

Order No. 872 also adopted a proposal to allow an entity seeking QF status to provide further information in its certification or re-certification to preemptively defend against rebuttal by identifying factors that show that its facility is indeed at a separate site from affiliated small power production QFs that are more than one mile but less than ten miles from it.¹⁷⁰ FERC identified the following examples of the factors it may consider in deciding whether small power production facilities that are owned by the same person(s) or affiliates are located at the “same site”:

(1) *physical characteristics*, including such common characteristics as: infrastructure, property ownership, property leases, control facilities, access and easements, interconnection agreements, interconnection facilities up to the point of interconnection to the distribution or transmission system, collector systems or facilities, points of interconnection, motive force or fuel source, off-take arrangements, connections to the electrical grid, evidence of shared control systems, common permitting and land leasing, and shared step-up transformers; and (2) *ownership/other characteristics*, including such characteristics as whether the facilities in question are: owned or controlled by the same person(s) or affiliated persons(s), operated and maintained by the same or affiliated entity(ies), selling to the same electric utility, using common debt or equity financing, constructed by the same entity within 12 months, managing a power sales agreement executed within 12 months of a similar and affiliated small power production qualifying facility in the same location, placed into service within 12 months of an affiliated small power production QF project’s commercial operation date as specified in the power sales agreement, or sharing engineering or procurement contracts.¹⁷¹

¹⁶⁹ *Id.* at P 491.

¹⁷⁰ *Id.* at P 492; 18 C.F.R. § 292.207(a)(2). See the discussion of certification requirements in Section II.B.4., *infra*.

¹⁷¹ Order No. 872 at P 509 (emphasis in original). Order No. 872 explains that “[d]efinitionally, if the facilities are not owned by the same person(s) or its affiliates, then the issue of compliance with the one-mile rule, even as revised in this final rule, becomes irrelevant. See 18 C.F.R. § 292.204(a)(1). That is, two facilities owned by two different persons are definitionally not located at the same site.” *Id.* at P 509 & n.797.

FERC reiterated in Order No. 872 that no one factor is dispositive and that it will conduct a case-by-case analysis to determine, based on the evidence, whether affiliated small power production QFs should be considered to be at the same site as the small power production facility seeking QF status.¹⁷²

In addition to these revisions to the presumptions and factors for implementing the 80 MW size limit for small power production QFs, Order No. 872 adopted the following definition of “electrical generating equipment”: “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.”¹⁷³ Order No. 872 further clarified that “each wind turbine at a wind facility 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.”¹⁷⁴ The point of measurement for the distance calculation will be from the edge of the electrical generating equipment closest to the affiliated small power production QF’s nearest electrical generating equipment.¹⁷⁵

¹⁷² *Id.* at P 511.

¹⁷³ *Id.* at P 515.

¹⁷⁴ *Id.* at P 521.

¹⁷⁵ *Id.* at P 523. FERC further clarified that (1) for a solar facility, the measurement should be from the edge of the small power production facility seeking QF status’ solar panel or inverter that is closest to the edge of the nearest “electrical generating equipment” of that affiliated small power production QF; and (2) for a wind facility, the measurement should be from the edge of the small power production facility seeking QF status’ wind turbine or inverter closest to the edge of the nearest “electrical generating equipment” of the affiliated small power production QF. FERC explained that for a wind facility, “the relevant point for measuring distance of an individual wind turbine is the tower (not the projection of the blade’s wingspans onto the ground)” and that “only horizontal distances are taken into consideration for purposes of this rule (such that elevation changes have no effect on facility distance).” *Id.*

¹⁷⁶ 18 C.F.R. § 292.204(a)(2)(ii); see also Order No. 872 at P 492 (FERC noted its retention of the waiver provision.).

¹⁷⁷ See *Pinellas Cty., Fla.*, 50 FERC ¶ 61,269 (1990) (“*Pinellas County*”).

¹⁷⁸ See Order No. 872-A at P 258 (FERC noted that it “has always determined whether to grant waivers on a case-by-case basis” and would continue to do so consistent with its waiver precedent.).

¹⁷⁹ 13 FERC ¶ 61,017 (1980) (“*Windfarms*”).

¹⁸⁰ *Id.* at 61,032. At issue in the *Windfarms* case was a request for waiver of a 30 MW limitation for exemption from state law, the FPA, or PUHCA, under PURPA section 210(e)(2), not the 80 MW size limitation for small power production QFs.

b) Waiver of the one-mile rule

In adopting the one-mile rule, FERC reserved discretion to modify its application for good cause.¹⁷⁶ FERC has clarified that while it has discretion to waive the one-mile rule to allow facilities to be located within one mile of each other, FERC cannot waive the limitation in PURPA that the production capacity for small power production QFs, together with any other facilities located on the same site, cannot be greater than 80 MW.¹⁷⁷

FERC applies its waiver provision on a case-by-case basis.¹⁷⁸ In limited cases, FERC has authorized waiver of the one-mile rule. For example, in *Windfarms, Ltd.*,¹⁷⁹ FERC granted such a waiver. The applicant requested a waiver of the one-mile rule for its three clusters of wind turbine generators, each of which was located at a separate and distinct site. FERC pointed out, among other things, that in light of the unconventional wind technologies and different natural resources involved, the one-mile rule could produce inappropriate results. FERC explained its belief that “it is fundamental to the concept of the ‘site’ of a facility that the area where the facility is located is in some manner distinct from the surrounding area. The distinction may be topographical, or it may relate to the energy resource being utilized, or some other aspect.”¹⁸⁰ FERC further determined that the

three areas at issue had “sufficiently distinct and identifiable topographical and energy resource-related characteristics so that each constitutes a ‘separate site’ for purposes of determining the aggregate capacity of the small power production facility located at each site.”¹⁸¹

In other instances, FERC has declined to waive the one-mile rule. For example, in *Pinellas County*, FERC determined that even if it had the authority to waive the one-mile rule for the proposed solid fuel facility that was located 600-700 feet from an existing solid waste field facility owned by the same entity, it would not do so. FERC found that economic savings as the sole reason for the proposed location of the second facility were an insufficient basis for waiver of the one-mile rule. FERC has similarly declined to grant waiver of the one-mile rule in instances where applicants do not sufficiently demonstrate that absent waiver, the resource would be wasted.¹⁸²

c) Fuel use

The primary energy source for qualifying small power production facilities, including those that employ storage components, must be biomass,¹⁸³ waste,¹⁸⁴ renewable resources, geothermal resources, or any combination, and 75 percent or more of the total energy input must be from these sources.¹⁸⁵ Energy storage facilities are subject to the same fuel use limitations as all other types of small power production facilities. FERC also permits “minor use” of fossil fuels in small power production facilities, consistent with Congress’ purpose of permitting such use in order to enhance the feasibility and efficiency of small power production facilities.¹⁸⁶ The use of fossil fuels by a small power production facility is limited to the minimum amounts of fuel required for uses including ignition, startup and alleviation or prevention of unanticipated equipment outages, and is limited to 25 percent of the total energy input of the facility per calendar year.¹⁸⁷

181 *Id.* at 61,033.

182 See *Vulcan/BN Geothermal Power Co., et al.*, 52 FERC ¶ 61,095, at 61,476-77 (1990) (FERC found that unlike the circumstances in *Windfarms*, the applicants here had not made any representation that the resource was concentrated in a distinct area that would prevent development absent waiver of the regulations).

183 See *supra* at n.136. The regulations provide that any “primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.” 18 C.F.R. § 292.204(b)(1)(ii).

184 See *supra* at n.137.

185 18 C.F.R. § 292.204(b)(1). See *Luz Dev. and Fin. Corp.*, 51 FERC ¶ 61,078, at 61,172 (1990) (“In sum, energy storage facilities such as the proposed Luz battery system are a renewable resource for purposes of QF certification. However, such facilities are subject to the requirement that the energy input to the facility is itself biomass, waste, a renewable resource, a geothermal resource, or any combination thereof or a demonstration that any fossil-fired input constitutes no more than 25 percent of the total energy input to the facility and such uses are consistent with those enumerated in section 3(17)(B) of the FPA.”).

186 See *LUZ Solar Partners, Ltd., et al.*, 30 FERC ¶ 61,122, at 61,226 (1985) (“Where a fossil fuel use improves the efficiency of those fixed assets of the small power production facility that are essential to the facility, the use of the fossil fuel in the small power production facility is consistent with congressional purposes, and will be permitted.”).

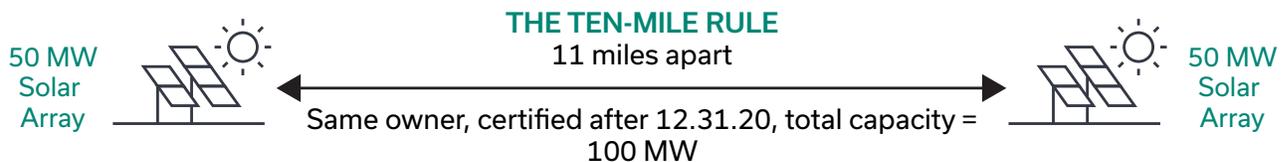
187 18 C.F.R. § 292.204(b)(2). FERC has granted waiver of the 25 percent limitation in some circumstances. See *Kramer Junction Co., et al.*, 61 FERC ¶ 61,309 (1992), *order on reh’g*, 64 FERC ¶ 61,025 (1993) (FERC granted a one-time waiver, limited to a single 120-day period, of the 25 percent limitation on fossil fuel use in order to alleviate financial hardship experienced by solar power producers due to a sharp reduction in solar-powered electrical generation allegedly attributable to climate changes resulting from a volcanic eruption.).

GET A MAP: BREAKING DOWN THE “ONE-MILE” RULE, THE “TEN-MILE” RULE, AND THE “ONE-TO-TEN MILE” RULE FOR SMALL POWER PRODUCTION FACILITIES

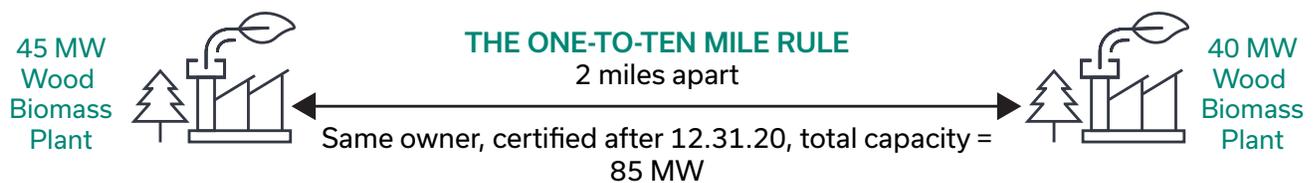
Maximum size — The power production capacity of a small power production QF, together with the power production capacity of any other small power production QFs that use the **same energy resource**, are owned by the **same person(s) or its affiliates**, and are located at the **same site**, may not exceed **80 MWs**. See 18 C.F.R. § 292.204(a)(1).



Neither facility qualifies as a QF, because they are located within one mile of each other and are therefore irrebuttably presumed to be at the **same site**. See 18 C.F.R. § 292.204(a)(2)(i)(A).



Both facilities qualify as QFs, because they are located more than ten miles apart and are therefore irrebuttably presumed to be at **different sites**. See 18 C.F.R. § 292.204(a)(2)(i)(B).



Both facilities can qualify as QFs. FERC’s regulations rebuttably presume that small power production QFs between one and ten miles apart are at different sites. However, electric utilities are allowed to challenge certifications or re-certifications with evidence to rebut this presumption. Relevant evidence could include factors relating to the physical characteristics of the facilities, such as whether they use common property ownership or leases, control facilities, interconnection facilities, or step up transformers, or ownership factors such as whether the facilities are financed through common debt or equity, use the same construction or engineering contracts, and/or are operated and maintained by the same entities or affiliates. See 18 C.F.R. § 292.204(a)(2)(i)(C) and Order No. 872 at PP 508-11.

2. CRITERIA AND REQUIREMENTS FOR QUALIFYING COGENERATION FACILITIES

The FERC regulations address two types of cogeneration facilities. The first is referred to as a “topping-cycle cogeneration facility” where the energy input to the facility is first used to produce electricity, and where at least some of the rejected heat from the power production process is used to provide useful thermal energy output.¹⁸⁸ “Useful thermal energy output” of a thermal energy topping-cycle cogeneration facility means the thermal energy (1) is made available to an industrial or commercial process; (2) is used in a heating application; (3) is used in a space cooling application; or (4) that is used by a fuel cell system with an integrated steam hydrocarbon reformation process for production of fuel for electricity generation.¹⁸⁹ The second type of cogeneration facility is referred to as “bottoming-cycle cogeneration” where the energy input to the system is first applied to a useful thermal energy application or process, and where at least some of the rejected heat from the application or process is then used for electricity production.¹⁹⁰ A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a QF if it (1) meets applicable criteria for operating and efficiency standards for topping-cycle facilities, efficiency standards for bottoming-cycle facilities,¹⁹¹ and criteria for new cogeneration facilities; and (2) unless

exempt, has filed with FERC a notice of self-certification or an application for Commission certification that has been granted.¹⁹²

d) Operating and efficiency standards for cogeneration facilities

i. Criteria for “existing” cogeneration facilities

The operating standard for topping-cycle cogeneration facilities is that the useful thermal output of the facility must be no less than 5 percent of the total energy output during the twelve-month period when the facility first produces electric energy, and any subsequent calendar year.¹⁹³ The efficiency standard for a topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, requires that the useful power output of the facility plus one-half the useful thermal energy output, during the twelve-month period when the facility first produces electric energy, and any subsequent calendar year, must (1) be no less than 42.5 percent of the total energy input of the natural gas and oil to the facility; or (2) if the thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.¹⁹⁴

¹⁸⁸ 18 C.F.R. 292.202(d).

¹⁸⁹ 18 C.F.R. § 292.202(h). In a Final Rule issued December 17, 2020, FERC amended the definition of “useful thermal energy output” in its PURPA regulations to include fuel cell systems with integrated hydrocarbon reformation equipment. *Fuel Cell Thermal Energy Output*, *Bloom Energy Corp.*, Order No. 874, 173 FERC ¶ 61,226 (2020).

¹⁹⁰ *Id.* at § 292.202(e).

¹⁹¹ The FERC regulations provide for waiver of the operating and efficiency standards upon a showing that the facility will produce significant energy savings. 18 C.F.R. § 292.205(c).

¹⁹² 18 C.F.R. § 292.203(b).

¹⁹³ 18 C.F.R. § 292.205(a).

¹⁹⁴ These operational and efficiency standards do not apply to facilities for which installation began prior to March 13, 1980. 18 C.F.R. §§ 292.205(a)(2)(i), (a)(2)(ii). FERC reviews requests for waiver of the operating and efficiency standards for cogeneration facilities on a case-by-case basis. See, e.g., *Central Power & Lime LLC*, 138 FERC ¶ 62,118 (2012); *Carson Cogeneration Co.*, 120 FERC ¶ 61,135 (2007); *Cedar Bay Generating Co., Ltd. P'ship*, 67 FERC ¶ 61,350 (1994); *LG&E-Westmoreland Hopewell*, 62 FERC ¶ 61,098 (1993).

For bottoming-cycle cogeneration facilities for which any of the energy input as supplementary firing is natural gas oil, the useful power output of the facility during the twelve-month period when the facility first produces electric energy, and any subsequent calendar year, must be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.¹⁹⁵

ii. Criteria for new cogeneration facilities

Cogeneration facilities that were not QFs on or before August 8, 2005, or that had not filed a notice of self-certification or an application for FERC certification as a qualifying cogeneration facility prior to February 2, 2006, and which seek to sell electric energy pursuant to PURPA section 210, are subject to criteria in addition to the operating and efficiency standards

discussed above. Specifically, such cogeneration facilities must also show: (1) the thermal energy output of the cogeneration facility is used in a productive and beneficial manner;¹⁹⁶ and (2) that the electrical, chemical and mechanical output of the cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and not intended fundamentally for sale to an electric utility. For purposes of the second criterion, the “fundamental use” requirement is met if at least 50 percent of the aggregate of the electrical, thermal, chemical and mechanical output of the cogeneration facility, on an annual basis, is used for industrial, commercial, residential or institutional purposes.¹⁹⁷

¹⁹⁵ 18 C.F.R. § 292.205(b)(1). There is no efficiency standard for bottoming-cycle facilities for which installation began prior to March 13, 1980. *Id.* at § 292.205(b)(2).

¹⁹⁶ In circumstances where a thermal host existed prior to the development of a new cogeneration facility whose thermal output will supplant the thermal source previously in use by the thermal host, the thermal output of the new cogeneration facility will be presumed to satisfy the requirement to demonstrate that the facility is used in a productive and beneficial manner.

¹⁹⁷ 18 C.F.R. § 292.205(d); see, e.g., *Med. Area Total Energy Plant, Inc. and New MATEP, Inc.*, 130 FERC ¶ 61,254 (2010) (FERC determined that steam and chilled water delivered by a cogeneration facility to hospital and medical customers are used in a productive and beneficial manner, and that 70 percent of the total energy output of the cogeneration facility was delivered to hospital and medical customers demonstrated that the electrical, thermal, chemical and mechanical output of the cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility).



3. SPECIAL REQUIREMENTS FOR HYDROELECTRIC SMALL POWER PRODUCTION FACILITIES LOCATED AT A NEW DAM OR DIVERSION

FERC's regulations provide that a hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion¹⁹⁸ is a QF if it meets the general maximum size, fuel use and certification provisions for small power production facilities as discussed above, as well as the following:

1. FERC finds, at the time it issues the license or exemption, that the project will not have a substantial adverse effect on the environment,¹⁹⁹ including recreation and quality;

2. FERC finds, at the time the application for the license or exemption is accepted for filing, that the project is not located on any settlement of a natural watercourse which is included or designated for potential inclusion in a state or national wild and scenic river system; or the state has determined to possess unique natural, recreational, cultural or scenic attributes which would be adversely affected by hydroelectric development; and
3. The project meets the terms and conditions set by the appropriate fish and wildlife agencies.²⁰⁰

In order to meet the QF requirement, hydroelectric small power production facilities must also comply with the rules for hydroelectric project licenses, permits, exemptions and determination of project costs.²⁰¹

198 "New dam or diversion" is defined as "a dam or diversion which requires, for the purposes of installing any hydroelectric project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards of similar adjustable devices)." 18 C.F.R. § 292.202(p).

199 "Substantial adverse effect on the environment" is defined as "a substantial alteration in the existing or potential use of, or a loss of, natural features, existing habitat, recreational uses, water quality, or other environmental resources. Substantial alteration of particular resource includes a change in the environment that substantially reduces the quality of the affected resources . . ." *Id.* at § 292.202(q).

200 18 C.F.R. § 292.208(b).

201 *Id.* at § 292.208(a)(3) (citing 18 C.F.R. Part 4).



4. CERTIFICATION REQUIREMENTS

There are two options for an entity to obtain QF status: self-certification (or re-certification) and Commission certification. There is an exemption from the filing requirement for generating facilities with net power production capacities of 1 MW or less.²⁰² Self-certification is the more commonly used method for QF certification.²⁰³ With respect to the two options, FERC has explained that it hoped that self-certifications would be the primary means of obtaining QF status.²⁰⁴ However, FERC also realized that there may be reasons that a QF may want or need certification by FERC, such as “the requirement of some lenders, utilities, or state regulators that a generator seeking QF status and the benefits of PURPA be Commission-certified before the lender, utility or state regulator would take action that would make a proposed QF a reality.”²⁰⁵

e. General requirements and process for self-certification and self-recertification

In order to self-certify the QF status of an existing or proposed facility that meets the criteria for QF status, the owner or operator of the facility, or its representative, must

(1) complete and submit Form No. 556 to FERC;²⁰⁶ and (2) provide notice of its self-certification or re-certification by serving a copy of the filing on each electric utility with which it expects to interconnect, transmit or sell electric energy to, or purchase supplementary,²⁰⁷ standby, back-up²⁰⁸ or maintenance power²⁰⁹ from, and the state regulatory authority of each state where the facility and each affected electric utility is located.²¹⁰ If the self-certification is for a “new” cogeneration facility, FERC will publish a notice in the Federal Register.²¹¹ FERC staff reviews the Form No. 556 submission in order to confirm that the information required in Form No. 556 appears to have been included, but notice is not typically published, and FERC staff does not otherwise evaluate whether the applicant’s facility meets the requirements for QF status.²¹² QF self-certification is effective upon filing, except that an electric utility is not required to purchase electric energy from a facility with a net power production of 500 kW or more until ninety days after the facility provides notification that it is a QF, or ninety days after the utility meets the notice requirements.²¹³ There is no fee for a self-certification.

202 *Revisions to Forms, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility*, Order No. 732, 130 FERC ¶ 61,214 (2010).

203 PURPA NOPR at P 143. According to the NOPR, FERC in recent years received approximately five applications per year for Commission certification and approximately 3,400 applicants filing for self-certification of their facilities. *Id.* at n.184.

204 See *Chugach Elec. Ass’n, Inc. and Matanuska Elec. Ass’n, Inc.*, 121 FERC ¶ 61,287, at P 21 (2007).

205 *Id.* (citing *Streamlining of Regulations Pertaining to Parts II and III of the Federal Power Act and the Public Utility Regulatory Policies Act of 1978*, Order No. 575, FERC Stats. & Regs. ¶ 31,014, at 31,275 (1995)).

206 18 C.F.R. § 292.207(a). If the owner/operator or its agent fails to file its notice of self-certification prior to making sales, FERC treats the sales as sales for resale made without FERC authorization under FPA section 205 and the refund remedy is (1) the time value of the revenues collected, calculated pursuant to section 35.19 of the FERC regulations for the entire period that the rate was collected without Commission authorization; and (2) all revenues resulting from the difference, if any, between the market-based rate and a cost-justified rate. See *N. Am. Nat. Res., Inc.*, 168 FERC ¶ 61,041 (2019).

207 “Supplementary power” is defined as “electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.” 18 C.F.R. § 292.101(b)(8).

208 “Back-up power” is “electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility’s own generation equipment during an unscheduled outage of the facility.” *Id.* at § 292.101(b)(9).

209 “Maintenance power” is “electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.” *Id.* at § 292.101(b)(11).

210 18 C.F.R. § 292.207(c)(1); see discussion of “new” cogeneration facilities in Section II.B.2.a)ii, *supra*.

211 18 C.F.R. § 292.207(c)(1).

212 PURPA NOPR at P 143.

213 18 C.F.R. § 292.207(c)(2), re-numbered § 292.207(e)(2) pursuant to Order No. 872.

f. Commission certification

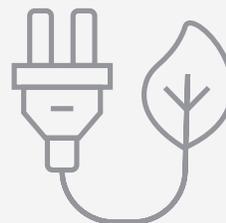
An owner or operator of an existing or a proposed facility, or its representative, may file with FERC an application for certification of QF status, together with the required fee.²¹⁴ The application must include a completed Form No. 556, and the applicant must provide notice by serving a copy of the filing on each electric utility with which it expects to interconnect, transmit, or sell electric energy to, or purchase supplementary, standby, back-up, or maintenance power from, and the state regulatory authority of each state where the facility and each affected electric utility is located.²¹⁵ FERC will publish a notice in the Federal Register for each application for Commission certification.²¹⁶

Within ninety days of the later of the filing of an application for certification of QF status or the filing of a supplement, amendment or other change to the application, FERC will either (1) inform the applicant that the application is deficient; or (2) issue an order granting or denying the application; or (3) toll the time for issuance of an order.²¹⁷ If FERC does not act within ninety days of the date of the latest filing, the application is deemed to have been granted.²¹⁸

g. Reforms adopted in Order No. 872

Because self-certification and self-recertification are effective upon filing, there generally has been no ability to challenge a self-certification.²¹⁹ Instead, in order to challenge a self-certification or self-recertification, the challenging entity has been required to file a petition for declaratory order requesting that FERC revoke the QF status of the facility and pay the associated filing fee.²²⁰

In Order No. 872, FERC adopted reforms to address the concern that challengers to the self-certification or self-recertification of a QF should not have to bear the burden of filing a petition for declaratory order and paying the associated filing fee. Significantly, an interested person or entity may now intervene and protest a self-certification or self-recertification of a QF and does not have to file a petition for declaratory order or pay the filing fee for petitions.²²¹ Order No. 872 made several reforms to the self-certification and self-recertification process, as follows:²²²



²¹⁴ 18 C.F.R. § 292.207(b)(1). The fee for an application for Commission certification as a qualifying small power production facility is \$23,330, and the fee for an application for Commission certification as a qualifying cogeneration facility is \$26,410. 18 C.F.R. § 381.505(a).

²¹⁵ *Id.* at § 292.207(c)(1).

²¹⁶ *Id.*

²¹⁷ *Id.* at § 292.207(b)(3)(i).

²¹⁸ *Id.*

²¹⁹ PURPA NOPR at P 146 (citing *Chugach Elec. Ass'n*, 121 FERC ¶ 61,287 at PP 51-54; *Hydro Inv'rs, Inc. v. Trafalgar Power, Inc.*, 94 FERC ¶ 61,207, at 61,780, *reh'g denied*, 95 FERC ¶ 61,120 (2001)).

²²⁰ *Id.*

²²¹ Order No. 872 at P 547. In order to address the concern that existing QFs could lose their QF status when they file their recertifications even if their recertifications implement or address non-substantive changes, Order No. 872 limits the ability to protest recertifications to only recertifications that make substantive changes to the existing certification. *Id.* at P 550.

²²² In Order No. 872, FERC also adopted corresponding revisions to its Form No. 556.

- *Protests and interventions:*²²³
 - Any person who opposes either a self-certification or a self-recertification making substantive changes to the existing certification, or an application to FERC for certification or recertification making substantive changes to the existing certification for which qualification or recertification is filed on or after December 31, 2020, may file a protest with FERC. Such protest must be filed on or before thirty days from the date the self-certification or self-recertification is filed, must be served pursuant to FERC's regulations, and must be adequately supported and provide any supporting documents, contracts or affidavits.
 - FERC granted "legacy" treatment to existing QFs, such that protests will not be allowed to QF self-certifications or self-recertifications (as well as QF certifications and re-certifications) that are submitted prior the December 31, 2020, effective date of Order No. 872. Once FERC has certified an applicant's QF status, any later protest to a self-recertification or an application for recertification making substantive changes to a QF's certification must demonstrate changed circumstances that call into question the continued validity of the existing certification.
- *Commission action:*²²⁴
 - The regulations state that self-certification and re-certification are effective upon filing. If no protests to a self-certification or re-certification are timely filed, no further action by FERC is required for a self-certification or recertification to be effective.
 - If protests to a self-certification or self-recertification are timely filed, a self-certification or self-recertification will remain effective until FERC issues an order revoking QF certification.²²⁵
 - FERC will act on a timely filed protest to a self-certification or self-recertification within ninety days from the date the protest is filed; if FERC requests further information from the protester, the entity seeking self-certification or self-recertification, or both, then the time for FERC to act will be extended to sixty days from the filing of a complete answer to the information request. FERC may toll the ninety-day period for one additional sixty-day period if required to rule on a protest, and the authority to do so is delegated to the FERC Secretary or the Secretary's designee.
 - Absent Commission action before the expiration of the tolling period, a protest will be deemed denied, and the self-certification or self-recertification will remain effective.

223 18 C.F.R. §§ 292.207(c)(1), (2). Note that these provisions apply to initial applications for certification and recertification, as well as initial self-certifications and self-recertifications.

224 18 C.F.R. § 292.207(a)(3).

225 FERC also clarified that when it issues an order revoking QF certification, such order is subject to rehearing and appeal pursuant to the FPA. Order No. 872 at P 561.

Order No. 872 also adopted provisions unique to certifications and recertifications by rooftop solar developers. FERC explained that rooftop solar developers frequently finance the initial development of rooftop solar PV systems of individual homeowners, then retain ownership until eventually transferred to the relevant homeowners.²²⁶ While the rooftop solar PV systems are owned by the developer, each individual rooftop solar PV system would be considered affiliated electrical equipment of every other rooftop solar PV system that is owned by that developer.²²⁷ Moreover, when 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.²²⁸ The addition of further rooftop solar PV systems to the developer's portfolio or transfer of ownership to the relevant homeowner could result in the facility being deemed as no longer conforming with the material facts in their prior certification or recertification and thereby trigger the need to recertify.²²⁹

In order to lessen the burden on rooftop solar PV developers when recertifying, Order No. 872 provides that rooftop solar PV developers have an option to file for recertification on

a quarterly basis. However, if in any quarter the 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 over the quarters since its last filing.²³⁰

h. Revocation of qualifying status

If a QF fails to conform with any of the material facts or representations presented by the cogenerator or small power producer in its submissions to FERC, the notice of self-certification or Commission order certifying the QF status of the facility may no longer be relied upon.²³¹ In such case, if the facility continues to conform to FERC's criteria for certification, then the cogenerator or small power producer may file either a notice of self-recertification of qualifying status, or an application for Commission recertification.²³² FERC may, on its own motion or the motion of any person, revoke the qualifying status of a facility.²³³ Prior to undertaking any substantial alteration or modification of a QF that has been certified, a small power producer or cogenerator can seek a Commission determination that the proposed alteration or modification will not result in revocation of qualifying status.²³⁴

²²⁶ *Id.* at P 559.

²²⁷ *Id.*

²²⁸ *Id.*

²²⁹ *Id.*

²³⁰ *Id.* at P 560.

²³¹ 18 C.F.R. § 292.207(d).

²³² *Id.*

²³³ *Id.* at §§ 292.207(d)(1)(ii), (d)(1)(iii); see, e.g., *Fountainview at Coll. Rd., Inc.*, 107 FERC ¶ 61,266 (2004) (FERC found that a QF self-certification could no longer be relied upon because the applicant submitted an incomplete Form No. 556 and had not responded to repeated requests to provide the information needed to complete the filing.); see also *Chugach Elec. Ass'n and Matanuska Elec. Ass'n*, 121 FERC ¶ 61,287 (2007) (FERC revoked the self-certifications of QF status for facilities that it determined were subject to the requirements for new cogeneration facilities and did not meet those requirements.).

²³⁴ 18 C.F.R. § 292.207(d)(2); see, e.g., *Occidental Geothermal, Inc. and Santa Fe Int'l Corp.*, 29 FERC ¶ 61,280 (1984) (FERC granted an application for determination that a change of ownership would not result in revocation of the qualifying small power production facility's status.).

C. ELECTRIC UTILITY OBLIGATIONS

The FERC regulations implementing PURPA section 210 create several obligations for arrangements between electric utilities and small power production QFs and cogeneration QFs. The electric utility obligations are set forth in FERC's PURPA regulations and include the following: (1) availability of avoided cost data; (2) obligation to purchase from QFs; (3) obligation to sell to QFs; (4) obligation to interconnect; and (5) parallel operation. Each of these is discussed below. Subsequent sections detail reforms (including Orders 872 and 872-A) to how these obligations can be satisfied and when the obligations become effective.

1. AVAILABILITY OF AVOIDED COST DATA

FERC requires that each electric utility with total sales of electric energy for purposes other than resale in excess of 500 million kilowatt-hours in any calendar year, to make available data from which avoided costs may be derived.²³⁵ Specifically, not

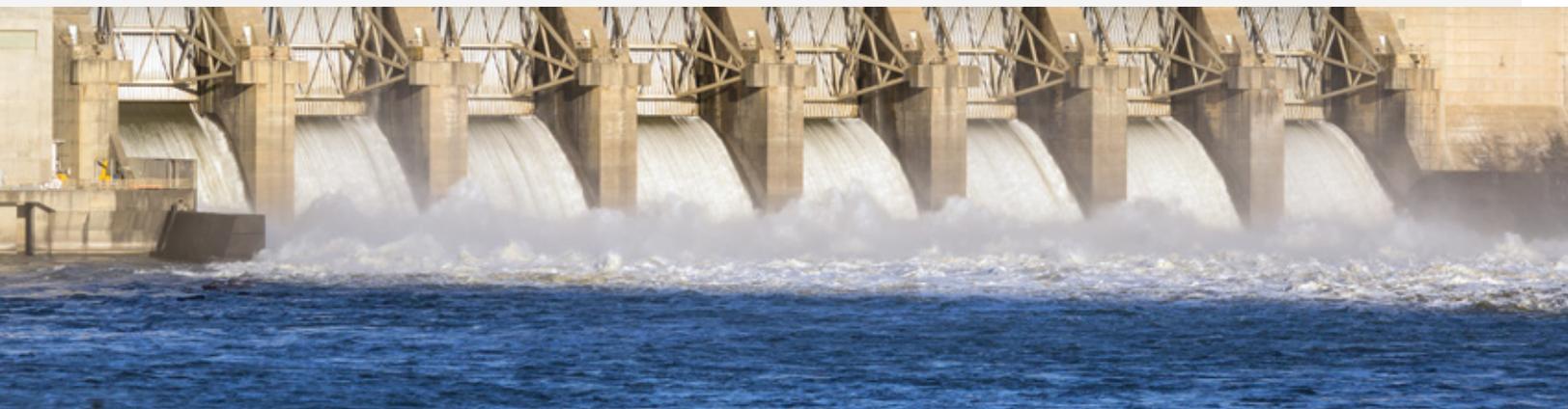
less than every two years, each regulated electric utility subject to the regulation shall provide to its state regulatory authority and maintain for public inspection, and each nonregulated electric utility shall maintain for public inspection, the following data: (1) the estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities, on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next five years;²³⁶ (2) the electric utility's plan for the addition of capacity by amount and type, for purposes of firm energy and capacity, and for capacity retirements for each year during the succeeding ten years;²³⁷ and (3) the estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, in cents per kilowatt hour and expressed in terms of individual generating units and of individual planned firm purchases.²³⁸

²³⁵ 18 C.F.R. § 292.302(a)(1).

²³⁶ *Id.* at § 292.302(b)(1).

²³⁷ *Id.* at § 292.302(b)(2).

²³⁸ *Id.* at § 292.302(b)(3).



For electric utilities with total sales of electric energy for purpose other than resale of less than 500 million kilowatt-hours during any calendar year, the regulations provide that upon request, the “small electric utility” shall make available data comparable to that required of electric utilities with calendar year sales in excess of 500 million kilowatt-hours, or with regard to an electric utility that is legally obligated to obtain all of its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.²³⁹ FERC’s regulations further provide that if a small electric utility fails to provide the information upon request, then the QF may apply to the state regulatory authority or FERC for an order requiring that the information be provided.²⁴⁰

FERC’s regulations provide for alternative data to the avoided cost data that would otherwise be required, if there is a determination that avoided costs can be derived from such data. The determination whether to substitute an alternative method of deriving avoided costs may be made by a state regulatory authority with respect to any electric utility over which it has ratemaking authority, or by the nonregulated electric utility.²⁴¹ In either case, if different data will be required, the state regulatory authority or nonregulated electric

utility must notify FERC within thirty days of making such determination.²⁴²

The FERC regulations also preserve a further role for state regulatory authorities with regard to the provision of avoidable cost data. Any avoided cost data submitted by an electric utility pursuant to the above-described regulations are subject to review by the state regulatory authority that has ratemaking authority over such electric utility.²⁴³

2. OBLIGATION TO PURCHASE FROM QFS

PURPA section 210 requires electric utilities to offer to purchase electric energy from qualifying cogeneration facilities and qualifying small power production facilities. FERC’s regulations implementing PURPA provide that each electric utility shall purchase any energy and capacity that is made available from a QF either directly to the electric utility, or indirectly to the electric utility pursuant to a provision that, if the QF agrees, the electric utility that would otherwise be obligated to purchase from the QF can transmit the energy or capacity to any other electric utility.²⁴⁴ FERC has found that electric utilities are required to purchase any energy and capacity made available by a QF, notwithstanding contractual provisions that might be used to limit or avoid

²³⁹ *Id.* at § 292.302(c)(1).

²⁴⁰ *Id.* at § 292.302(c)(2). In a series of orders, FERC addressed a request that it require specific electric utilities to provide their avoided costs stated in cents per kWh and to include justification of the data provided. In *Gregory and Beverly Swecker v. Midland Power Coop.*, 162 FERC ¶ 61,146 (2018); *reh’g denied*, 166 FERC ¶ 61,205 (2019), FERC found that the electric utilities had provided prices for combined energy and capacity or for energy only along with seasonality payments and projected payments. FERC found that the data provided satisfied the requirement for the small electric utilities to provide comparable data to the avoided cost data required to be provided by electric utilities. Therefore, FERC denied the request for an order directing further cost data.

²⁴¹ 18 C.F.R. § 292.302(d)(1).

²⁴² *Id.* at § 292.302(d)(2).

²⁴³ *Id.* at § 292.302(e)(1). In such review, the electric utility has the burden of coming forward with justification for its data. *Id.* at § 292.302(e)(2).

²⁴⁴ 18 C.F.R. § 292.303(a).

the purchase obligation.²⁴⁵ However, the FERC regulations provide for an electric utility to terminate its obligation to purchase electric energy from a QF if FERC finds that the QF has nondiscriminatory access to certain markets.²⁴⁶

3. OBLIGATION TO SELL TO QFS

Each electric utility is obligated to sell to any QF energy and capacity as requested by the QF. Such sales must be in accordance with the rate provisions of FERC's PURPA regulations at 18 C.F.R. § 292.305.²⁴⁷ As with the obligation to purchase from QFs, electric utilities can seek termination of the obligation to sell to QFs.²⁴⁸



4. OBLIGATION TO INTERCONNECT

Electric utilities are required to make such interconnection with QFs as may be necessary to accomplish the obligation to purchase or sell, except that no electric utility is required to interconnect with a QF if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to FERC regulation as a public utility under Part II of the FPA.²⁴⁹ FERC's regulations further provide that QFs must pay any interconnection costs which the state regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the QF on a nondiscriminatory basis with respect to other customers with similar load characteristics.²⁵⁰ The applicable state regulatory authority and nonregulated electric utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.²⁵¹

245 See *Delta-Montrose Elec. Ass'n*, 151 FERC ¶ 61,238 (2015); *reh'g denied*, 153 FERC ¶ 61,028 (2015) (FERC issued a declaratory order finding, among other things, that a rural electric cooperative was obligated to purchase power from QFs offering available capacity and energy, notwithstanding the electric cooperative's contract to purchase at least 95 percent of its needs for capacity and energy from the generation and transmission cooperative to which it belonged as a member.)

246 See Section II.F.1., *infra*, for a discussion of the requirements for termination of obligation to purchase from QFs. Several electric cooperative utilities and their members have also received waivers of the QF purchase and sale obligations in order to pursue PURPA implementation plans. Municipal joint action agencies have received similar waivers. Typically, the electric cooperative and its members seek reciprocal waivers of the purchase and sale obligations such that the cooperative utility assumes its members' obligations to purchase from QFs, and the member cooperatives assume the obligation to sell to QFs capacity and energy as provided in 18 C.F.R. §§ 292.303(b) and 292.305(b)(1). See *Old Dominion Elec. Coop.*, 170 FERC ¶ 62,094 (2020); *W. Farmers Elec. Coop.*, 115 FERC ¶ 61,323 (2006); *accord Seminole Elec. Coop., Inc., et al.*, 39 FERC ¶ 61,354 (1987); *Oglethorpe Power Corp., et al.*, 32 FERC ¶ 61,103 (1985), *reh'g granted in part and denied in part*, 35 FERC ¶ 61,069 (1986), *aff'd sub nom. Greensboro Lumber Co. v. FERC*, 825 F.2d 518 (D.C. Cir. 1987); *cf. Hoosier Energy Rural Elec. Coop., Inc.*, 154 FERC ¶ 62,205 (2016); *N.C. Elec. Membership Corp.*, 137 FERC ¶ 62,009 (2011).

247 18 C.F.R. § 292.303(b).

248 *Id.* (citing 18 C.F.R. § 292.312). See Section II.F.1.a), *infra*, for a discussion of the requirements for termination of the obligation to sell to QFs.

249 18 C.F.R. §§ 292.303(c)(1), (c)(2).

250 *Id.* at § 292.303(c)(1); 18 C.F.R. § 292.306.

251 18 C.F.R. § 292.306(b).

Compliance Basics for Electric Utilities

PURPA applies to “electric utilities,” which, broadly defined, include any entity that sells electric energy. This includes investor-owned utilities, public power entities such as municipal utilities, and rural electric cooperatives.

Electric utilities have a number of obligations under PURPA. The most important are:

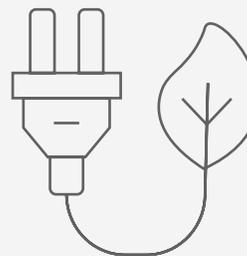
- Making system avoided cost data publicly available, and, for state-regulated electric utilities, filing the data with the appropriate state commission.
- The system avoided cost data is intended to provide information about the system avoided costs for energy and capacity.
- This information is described in detail in FERC’s regulations at 18 C.F.R. § 292.302.

- Purchasing energy and capacity from qualifying facilities at your electric utility’s “avoided cost”.
- Selling power to qualifying facilities.
- Interconnecting qualifying facilities.

Best practices for PURPA compliance:

Learn about and manage the legal and regulatory issues:

- Become familiar with the avoided cost data requirements in the FERC regulations and prepare and regularly update the system avoided costs.
- If you are regulated at the state level, your state commission likely has laws or regulations that implement PURPA. Become familiar with these requirements.





Identify approaches to managing PURPA issues as they arise:

- For both state-regulated utilities and nonregulated utilities, consider adopting protocols for managing inquiries from PURPA resources, responding to requests for pricing information, and establishing when a legally enforceable obligation is formed.
- Have a plan for dealing with interconnection requests from qualifying facilities:
 - Know whether state rules are applicable and what those rules are.
 - Learn about the basics of FERC interconnection requirements, even if you are not FERC-jurisdictional under the Federal Power Act.

Understand your options to modify or eliminate PURPA obligations:

- You may be eligible to terminate the “must-purchase” obligation from some qualifying facilities, especially if your utility is a participant in one of the organized markets administered by a regional transmission organization or independent system operator.
- If you are a municipal joint action agency, a G&T electric cooperative, or a party to an all or all-supplemental power supply contract with another party, you may be entitled to transfer the must-purchase obligation to your supplier.
 - Note that some electric utilities will need to coordinate closely with the state regulatory authority.

Helpful resources:

- FERC’s Regulations – 18 C.F.R. Part 292
- The FERC website’s PURPA page – [PURPA Qualifying Facilities | Federal Energy Regulatory Commission \(ferc.gov\)](#)

D. DETERMINING AVOIDED COST

Perhaps the most challenging implementation issue for state regulatory authorities and nonregulated electric utilities in the decades since PURPA was enacted has been the determination of the applicable avoided cost rate. Various methodologies have emerged as a way to satisfy the PURPA statute's requirement that the rates for sales of energy by QFs to electric utilities are "(1) just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against qualifying cogenerators or qualifying small power producers."²⁵² In an effort to more closely align its PURPA pricing policies with the maturation of the organized energy markets and the proliferation of non-PURPA renewables, FERC has more recently adopted in Order No. 872 significant reforms to its PURPA regulations relating to the rates at which electric utilities must purchase the output of QFs. These reforms, discussed below, attempt to balance the statutory requirement for "encourage[ment] of cogeneration and small power production"²⁵³ with current market realities.

In addition to the foregoing requirements, PURPA establishes a cap²⁵⁴ on the rates to which QFs are entitled, expressly prohibiting

FERC from adopting regulations that "provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."²⁵⁵ The "[i]ncremental cost of alternative electric energy" is defined as the "cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."²⁵⁶

In Order No. 69, FERC implemented PURPA's pricing provisions by expanding upon the statute's definition of "incremental cost of alternative electric energy," explaining that its adopted term "avoided costs" represents "the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source."²⁵⁷ FERC continued, confirming that the avoided cost:

²⁵² 16 U.S.C. § 824a-3(b).

²⁵³ *Id.* at § 824a-3(a) (directing FERC to prescribe regulations to "encourage" QFs through rules mandating that electric utilities "offer" to purchase electric energy from and sell electric energy to QFs).

²⁵⁴ In the Conference Report that accompanied PURPA, the conference committee wrote that the "limitation on the rates which may be required in purchasing from a cogenerator or small power producer is meant to act as an upper limit on the price at which utilities can be required . . . to purchase electric energy." H.R. Rep. No. 95-1750, at p. 98 (1978).

²⁵⁵ 16 U.S.C. § 824a-3(b).

²⁵⁶ *Id.* at § 824a-3(d).

²⁵⁷ Order No. 69, 45 FR at 12216.



[I]ncludes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy Costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.

If, by purchasing electric energy from a [QF], a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a [QF] is to be based on those energy costs which the utility can thereby avoid. If a [QF] offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs.²⁵⁸

With regard to the term "incremental," FERC stated that "[u]nder the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost . . . [A]n economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a [QF]."²⁵⁹ For this reason, FERC determined that the "utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs."²⁶⁰ Similarly, FERC explained that the cost of avoided capacity additions should be reflected as the avoided cost and "not the average embedded system cost of capacity."²⁶¹

As noted elsewhere in this Manual, Order No. 69 resulted in FERC's initial set of implementing regulations related to the obligations of electric utilities under PURPA, including the "must purchase" obligation and the requirement to compensate QFs at the avoided cost. The regulations relating to the rates for purchases from QFs are set forth at 18 C.F.R. § 292.304. In addition to providing for the statutory standards of being just and reasonable to consumers, in the public interest, and nondiscriminatory, the regulations confirm that "[n]othing in this subpart requires any electric utility to pay more than the avoided costs for purchases."²⁶²

²⁵⁸ *Id.*

²⁵⁹ *Id.*

²⁶⁰ *Id.*

²⁶¹ *Id.*

²⁶² 18 C.F.R. § 292.304(a)(2).

FERC's implementing regulations provide QFs with options to choose how they will provide and be compensated for energy and/or capacity: whether on an "as available" basis, "in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery," or, alternately, "pursuant to a legally enforceable obligation over a specified term," which, in

turn, permits QFs to elect avoided cost rates calculated either at the time of delivery or at the time the legally enforceable obligation is incurred.²⁶³

The regulations also specify a number of factors that "shall, to the extent practicable," be taken into account in formulating avoided cost rates for purchases:

- (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
- (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
 - (i) The ability of the utility to dispatch the qualifying facility;
 - (ii) The expected or demonstrated reliability of the qualifying facility;
 - (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
 - (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
 - (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
 - (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
 - (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
- (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
- (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.²⁶⁴

²⁶³ *Id.* at § 292.304(d). FERC substantially revised its regulations at § 292.304(d) in Order No. 872 effective as of December 31, 2020.

²⁶⁴ 18 C.F.R. § 292.304(e). As with § 292.304(d), § 292.304(e) is likewise revised as of December 31, 2020 pursuant to Order No. 872.

Although the general framework set forth above was, in significant part, retained by FERC in Order No. 872, Order No. 872 nonetheless extensively revises FERC's regulations related to the applicable rates for purchases. These modifications are discussed in detail in the sections below, and the regulations, as revised in accordance with Order No. 872, are appended to this Manual.

1. ORDER NO. 872 AND EXPANSION OF AVOIDED COST RATES TO INCLUDE MARKET-BASED PRICING

Order No. 872 reflects a shift to permit state regulatory authorities and nonregulated electric utilities to utilize competitive, market-based pricing metrics consistent with FERC's objective of updating and modernizing its PURPA regulations and policies to reflect current industry conditions. The changes to FERC's authorized pricing methodologies under PURPA now expressly permit state regulatory authorities and nonregulated electric utilities to use prices generated by the wholesale electricity markets regulated by FERC and prices at liquid, competitive market hubs to establish electric utilities' avoided energy costs. It also permits energy rates to vary over a contract term, allows use of forward pricing curves establishing projections of market prices, and confirms the use of auction and Request for Proposal ("RFP") processes to establish avoided cost rates.

Order No. 872 also preserves the existing bifurcation of the costs and compensation for energy and capacity, with a resource's fixed costs recovered through fixed capacity rates and variable costs recoverable through variable energy rates, as follows:

The NOPR proposal (which we adopt in this final rule) gave states the flexibility, should they choose to take advantage of this 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 at the time the LEO is incurred) . . . We are retaining in this final rule the option granted to QFs to fix their capacity rates for the term of their contracts at the time the LEO is incurred . . .

[A] fixed capacity rate in a QF contract based on a purchasing electric utility's capacity rates should typically be sufficient to recover the QF's financing costs and should therefore continue to facilitate QF financing.²⁶⁵

FERC acknowledged "that this is the standard rate structure used throughout the electric industry for power sales agreements that include the sale of capacity" and explained that:

[T]his provides flexibility to states to ensure that the avoided cost rate will be closer to the actual rate the purchasing electric utility and its customers would have paid if the purchasing electric utility had generated this electric energy itself or purchased such electric energy from another source. Furthermore, the record evidence demonstrating significant amounts of non-QF generation facilities in operation today shows that the owners of such facilities are able to obtain financing based on this same variable energy rate/fixed capacity rate construct.²⁶⁶

²⁶⁵ Order No. 872 at PP 36-37.

²⁶⁶ *Id.* at P 38. FERC added, "QF variable energy rate/fixed capacity rate contracts not only would be structured similarly to the standard wholesale power sales agreements used in the electric industry, but application of traditional cost-based ratemaking principles to sales by QFs is exactly what would be required in order to provide QFs with the same guaranteed cost recovery . . . Guaranteeing QFs cost recovery is fundamentally inconsistent with PURPA . . ." *Id.* at P 41.

Order No. 872's integration of market-oriented pricing into the PURPA regulations governing avoided cost rates is achieved through the following policies:

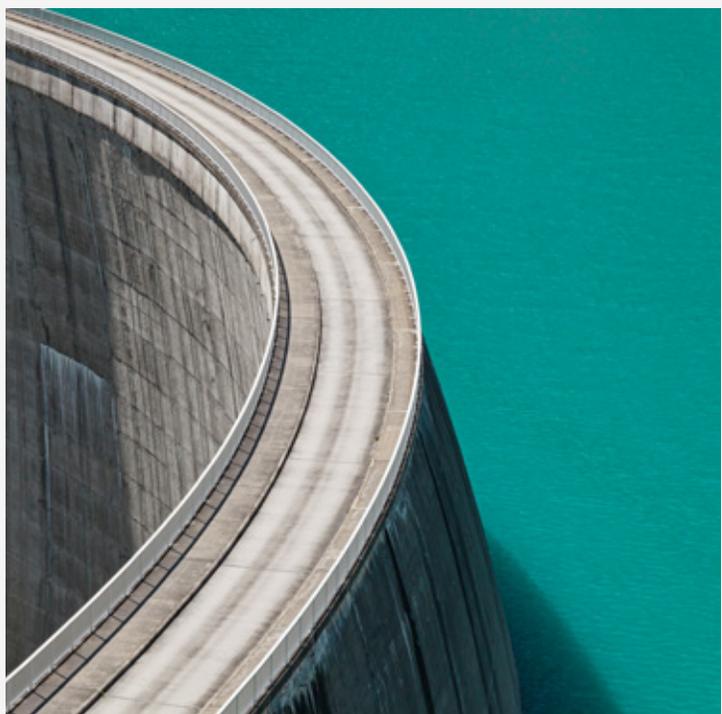
- The energy rates in QF PPAs and other LEOs may vary in accordance with changes in the purchasing electric utility's as-available avoided costs at the time the energy is delivered. Under this change, if a state regulatory authority or nonregulated electric utility exercises this flexibility, a QF no longer would have the ability to elect to have its energy rate fixed, but would continue to be entitled to a fixed capacity rate.
- LMPs may be used to establish avoided energy costs both for short-term, "as available" sales and for long-term energy sales pursuant to a LEO.²⁶⁷ The LMPs produced by organized energy markets are rebuttably presumed to represent the as-available avoided costs of electric utilities in those markets.
- For utilities operating outside of organized energy markets where LMPs are not available, the Final Rule permits reliance on competitive prices from market hubs (such as, for example, the Mid-Columbia or Palo Verde hubs)²⁶⁸ or derived formulaically based on price indices for natural gas and heat rates for combined cycle gas units.²⁶⁹
- In the event that a state regulatory authority or nonregulated electric utility elects to permit fixed energy rates in QF PPAs, the fixed energy rate may be based on a projection of market-based energy prices during the term of a QF contract and based on the anticipated dates of delivery. The "fixed" 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."²⁷⁰
- State regulatory authorities and nonregulated electric utilities have the flexibility to set energy and capacity rates pursuant to competitive solicitation processes conducted pursuant to transparent and nondiscriminatory procedures.

²⁶⁷ See *id.* at PP 114-119, 151-54.

²⁶⁸ See *id.* at PP 189-91, 201.

²⁶⁹ *Id.* at P 211. The Final Rule acknowledges that factual determinations could be made to base costs on generating units or technology types other than natural gas. See *id.* at P 214.

²⁷⁰ *Id.* at P 227.



2. PERMISSIBILITY OF VARIABLE ENERGY RATES

Order No. 872 revised FERC's PURPA regulations to provide that state regulatory authorities and nonregulated electric utilities may establish variable avoided cost rates, rather than fixed avoided cost rates, for electric energy sales made pursuant to LEOs. Under this change, such rates would vary and be based upon the avoided cost of electric energy at the time of delivery.²⁷¹ FERC determined that the record in its rulemaking proceeding "overwhelmingly" supported its conclusions that long-term forecasts of avoided energy costs are "inherently less accurate,"²⁷² thereby creating price risk for electric utilities and their consumers. QFs would retain their entitlement under FERC's existing regulations to capacity payments at an avoided cost rate fixed at the time the LEO was incurred.²⁷³ To implement this change, FERC directed that the following language be added to its regulations at 18 C.F.R. § 292.304(d)(2):

[A] state regulatory authority or nonregulated electric utility may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery.²⁷⁴

3. USE OF COMPETITIVE MARKET PRICES TO SET AVOIDED COST RATES

a) Locational marginal prices

In Order No. 872, FERC adopted a new policy expressly permitting electric utilities to set the avoided cost rates for as-available energy purchases at market-based prices. In establishing this policy, FERC reasoned that:

A QF has no obligation under the as-available avoided cost rate provisions to deliver any set amount of electric energy at any point in the future, but merely is paid for the amount of electric energy actually delivered. Therefore, the delivery of as-available energy does not displace any long-term energy the purchasing electric utility would generate itself or purchase from another source but rather allows the purchasing utility to reduce the amount of energy it otherwise would generate itself or purchase from another entity at the time the QF delivers the energy. Because the QF has no obligation to deliver any energy in the future, the utility is unable to avoid constructing or contracting for capacity to meet its future needs as a consequence of the delivery of energy by the QF. As-available energy rates therefore appropriately reflect only the short-run value of energy delivered at the particular moment in time when and if the QF has energy available to be delivered to the utility.

²⁷¹ *Id.* at P 253.

²⁷² *Id.* at PP 254 & n.403; see also *id.* at 257-58 (explaining that FERC was exercising its discretion to shift this price risk away from electric utility consumers) and 283 (finding that "prices for energy can exceed and have exceeded avoided cost for energy, without any subsequent balancing out").

²⁷³ *Id.* at P 337.

²⁷⁴ *Id.*, Appendix at P 6.

A QF can displace an electric utility's own generation or purchases from alternative sources over the long-run when a QF sells capacity to a utility in addition to as-available energy.²⁷⁵

FERC determined that LMPs from the regulated energy markets would be rebuttably presumed to represent the avoided cost energy rate for as-available energy sales by a QF. The regulated energy markets include those administered by NYISO, ISO-NE, MISO, SPP, CAISO, and PJM, as well as the Western Energy Imbalance Market ("EIM").²⁷⁶ According to FERC, "LMP sets day-ahead and real-time energy prices through competitive auctions in [regional transmission organizations and independent system operators ("RTOs/ISOs")] that optimally dispatch resources to balance supply and demand, while taking into account actual system conditions including congestion on the transmission system."²⁷⁷ FERC went on to find that:

(1) LMPs reflect the true marginal cost of production of energy, taking into account all physical system constraints; (2) these prices would fully compensate all resources for their variable cost of providing service; (3) LMP prices are designed to reflect the least-cost of meeting an incremental megawatt-hour of demand at each location on the grid, and thus prices vary based on location and time; and (4) unlike average system-wide cost measures of the avoided energy cost

used by many states, LMP should provide a more accurate measure of the varying actual avoided energy costs, hour by hour, for each receipt point on an electric utility's system where the utility receives power from QFs.²⁷⁸

b) Market hubs

For regions outside of the organized energy markets, FERC stated that pricing data from liquid market hubs could be used to establish the avoided cost energy rates for QF sales.²⁷⁹ However, prior to adopting avoided cost pricing based on market hubs, the state regulatory authority or nonregulated electric utility must find that the hub in fact represents the purchasing electric utility's avoided cost and is appropriately used for this purpose. For example, such findings could be based on the following (non-exhaustive) list of factors:

(1) whether the hub is sufficiently liquid that prices at the hub represent a competitive price; (2) whether the prices developed at the hub are sufficiently transparent; (3) whether the electric utility has the ability to deliver power from such hub to its load, even if its load is not directly connected to the hub; and (4) whether the hub represents an appropriate market to derive an energy price for the electric utility's purchases from the relevant QFs given the electric utility's physical proximity to the hub.²⁸⁰

²⁷⁵ Order No. 872 at P 118-19.

²⁷⁶ See *id.* at P 177-79 (finding that the Western EIM prices may presumptively be used to establish avoided costs for as-available energy by purchasing electric utilities that are able to participate in that market). Presumably, LMPs produced by the emerging SPP-administered Western Energy Imbalance Services market would likewise qualify.

²⁷⁷ *Id.* at P 153.

²⁷⁸ *Id.*

²⁷⁹ In Order No. 872, FERC determined that prior use of these hubs to set avoided cost energy rates was not impermissible. See Order No. 872 at P 200.

²⁸⁰ *Id.* at P 190.

c) Gas price indices

Finally, FERC also approved the use of gas price indices and a proxy heat rate, plus variable operations and maintenance costs, as an avoided cost pricing measure for QF energy sales.²⁸¹ Without significant discussion, FERC found that not only do state regulatory authorities and nonregulated electric utilities currently have the flexibility to adopt this methodology, but such a methodology in fact may represent a utility's actual avoided costs of alternate supply it would either generate itself or obtain from another source.

4. FORWARD PRICE CURVES

Likewise adopting a methodology that it acknowledged has previously been in use by some state regulatory authorities and nonregulated electric utilities, FERC, "given the flexibilities" it adopted in Order No. 872 "with respect to competitive market prices and variable energy rates," clarified that state regulatory authorities and nonregulated electric utilities may use forecasts of market prices to determine either a fixed energy rate or, alternately, set prices that would vary according to a predetermined interval as specified in a PPA.²⁸² FERC explained that

The fixed energy rate component of the contract 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. We also will allow the state 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.²⁸³

FERC referred to these forecasts as "forward price curves," and explained that these metrics provide transparency, but cautioned that the forward price curve must "meaningfully and reasonably reflect the utility's avoided costs over time."²⁸⁴

5. REBUTTABLE PRESUMPTIONS

In the event that one or more of the above-referenced avoided cost pricing methodologies is adopted, Order No. 872 establishes a "rebuttable presumption" that LMP or hub-based energy rates may be used as representative of an electric utility's avoided costs. QFs may contest these methodologies on the basis that they do not represent the electric utility's true avoided cost. Because, however, FERC will rebuttably presume that market-based pricing is an acceptable

²⁸¹ *Id.* at P 211.

²⁸² *Id.* at P 227.

²⁸³ *Id.*

²⁸⁴ *Id.* at P 230.



methodology, if a QF seeks to contest use of LMPs or market prices for avoided energy costs, the QF (rather than the utility) has the burden of coming forward with evidence to contest reliance on market prices.

6. COMPETITIVE SOLICITATIONS

Order No. 872 expressly permitted continued use, by state regulatory authorities and nonregulated electric utilities, of competitive solicitations and similar auction mechanisms to establish avoided cost rates, subject to the condition that such procurement processes be conducted in an open, transparent, and nondiscriminatory way. To achieve these objectives, FERC ruled that competitive solicitation processes must meet certain criteria, including the following minimum requirements:

- (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.²⁸⁵

According to FERC, it supports competitive solicitations based upon the following policy benefits:

[A]s a means to foster competition in the procurement of generation and to encourage the development of QFs in a way that most accurately reflects a purchasing utility's avoided costs. We believe that allowing QFs to compete to provide capacity and energy needs, through a properly administered competitive solicitation, may help ensure an accurate determination of the purchasing electric utility's avoided cost, and therefore result in prices meeting the PURPA's statutory requirements. We also believe that it is reasonable for states to choose to require QFs to be responsive to price signals as to where and when capacity is needed. We believe that a properly administered competitive solicitation can help provide such price signals.²⁸⁶

FERC also explained that competitive solicitations may aid in fostering the development of competitive markets in geographic regions outside of ISOs and RTOs.²⁸⁷

Use of competitive solicitations remains optional, but Order No. 872 explains that, under appropriate circumstances, competitive solicitations could constitute the sole means through which an electric utility would establish its avoided cost rates, if, for example, the utility does not engage in self-building or procure power through contractual arrangements outside of the competitive solicitation process.²⁸⁸ If a state regulatory authority (as to one of its regulated electric utilities) or nonregulated electric utility reflected all of the alternate means of

²⁸⁵ *Id.* at P 413.

²⁸⁶ *Id.* at P 416.

²⁸⁷ *Id.* at P 417.

²⁸⁸ *Id.* at P 421.

procuring power supply in the competitive solicitation process, then QFs that were unsuccessful bidders in that process would receive \$0 capacity rates through that process, on the basis that the utility's needs are fully met by the competitive solicitation.²⁸⁹ In such circumstances, however, the QF would still have the ability to sell its energy output to the utility at an avoided cost energy rate.²⁹⁰ If the state or nonregulated electric utility does not reflect all self-building or procurement in the competitive solicitation process, then the fact that a QF did not prevail in the competitive solicitation does not mean that it is precluded from recovery of both an energy and a capacity payment; in the event that the utility does still have a demonstrable need for capacity that could be met through self-building, other PPA processes, or via QF procurement, then the QF would be eligible for compensation through avoided cost energy and capacity rates.²⁹¹ As FERC explained, "[t]o be clear, the competitive solicitation is not to be a means to determine a QF's right to put as-available energy to the utility. But the competitive solicitation can be the means to determine what, if any, rate the QF will be paid for capacity."²⁹²

To satisfy its criteria for openness and transparency, FERC ruled that competitive solicitation processes must satisfy what it refers to as its "*Allegheny*" criteria. These criteria, derived from FERC's order in *Allegheny Energy Supply Co., LLC*,²⁹³ provide for competitive solicitations to be conducted with:

(1) transparency, a requirement that the solicitation process be open and fair; (2) definition, a requirement that the product, or products, sought through the competitive solicitation be precisely defined; (3) evaluation, a requirement that the evaluation criteria be standardized and applied equally to all bids and bidders; and (4) oversight, a requirement that an independent third party design the solicitation, administer bidding, and evaluate bids prior to selection.²⁹⁴

7. OTHER METHODS

In addition to the foregoing pricing methods described in Order No. 872, other methodologies for establishing an electric utility's avoided cost rates have been developed since PURPA was originally implemented. Several of the more significant methodologies are described below.

Proxy resource method. This method bases the avoided cost on the cost of the host utility's next planned addition, typically a combined cycle/gas turbine ("CCGT") generating unit. This approach essentially assumes that the QF substitutes for a planned utility generating unit, or what is assumed to be the next generating unit. The proxy unit's estimated fixed cost (annualized over the expected life of the unit) determines the avoided capacity cost, and the estimated variable cost sets the avoided energy cost.

289 *Id.* at PP 421-22. By way of policy rationale, FERC explained that it was attempting to mitigate the risks to electric utilities from, for example, a QF "simply sit[ting] out the competitive solicitation process (or participate but not have their bids accepted), but then seek to sell capacity to the purchasing electric utility and to receive a separate higher administratively-determined avoided cost rate including an avoided cost capacity rate, and even potentially displace non-QF competitive solicitation winners." *Id.* at P 424.

290 *Id.* at P 422.

291 *Id.* at PP 423-24. See also *Hydrodynamics Inc., et al.*, 146 FERC ¶ 61,193, at P 32-33 (2014) (explaining that where a competitive solicitation process is the only way in which a QF may obtain a long-term avoided cost rate, there is "a practical disincentive to amicable contract formation," where "a utility may refuse to negotiate with a QF at all" and contract formation may be precluded entirely in a year where a competitive solicitation process is not held.) (citations omitted).

292 Order No. 872 at P 424.

293 108 FERC ¶ 61,082 (2004).

294 Order No. 872 at P 430.

The type and size of the unit or units is determined in an Integrated Resource Process or from the utility's planning process, where the planning process, for regulated utilities, follows a state regulatory authority-approved procedure. Because this is a relatively simple method to use, the proxy method is very common, although the results largely depend on the type of unit or units chosen as the proxy.

Peaker method. Under the peaker method, the value of the QF's capacity is determined by assuming that the QF will be operating as a utility peaking unit. If the utility requires capacity, this method sets the avoided capacity at the lowest-cost capacity option available to the utility, for example, a combustion turbine. Avoided energy cost may be based on the utility's system-wide avoided energy cost, not the peaking unit's energy cost. This requires production cost modeling to determine the system-wide avoided energy cost, which increases the complexity of this method over the "proxy" unit approach.

Partial displacement differential revenue requirement. Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF. This assumes that the addition of the QF or QFs will reduce the utility's system revenue requirement. Also, this method assumes that the utility is subject to rate base/rate-of-return regulation for the generation facilities, where a revenue requirement is being determined and can be used as the basis. This method essentially calculates both energy and capacity (when required) cost simultaneously. Also required is the use of a planning expansion

model to run scenarios both with and without the QF or QFs, and then a financial planning model to determine the revenue requirements under each scenario.

Fuel index rates. This approach is similar to the "peaker" method in that it uses an on-peak capacity cost adder, but adds a variable monthly gas index price to determine avoided energy cost.

8. PRICING CONSIDERATIONS WHEN AN ELECTRIC UTILITY DOES NOT NEED ENERGY OR CAPACITY

It is well established that, when an electric utility is able to demonstrate that it has no need for additional capacity, it does not avoid any capacity costs through QF procurement, and its avoided cost rates for capacity may be set at \$0. However, notwithstanding the absence of need for additional capacity resources, electric utilities are nonetheless presumed to need energy.

Section 292.303(a) of the PURPA regulations requires that utilities purchase "any energy and capacity which is made available from a qualifying facility."²⁹⁵ Subject to the current exemption for purchases from QFs over 20 MW that many utilities in organized markets have obtained,²⁹⁶ the requirement establishes a must-take obligation for QF production as to both energy and capacity regardless of need. Indeed, FERC recently reiterated its regulation that specifically requires a utility to purchase "any energy and capacity made available by a QF."²⁹⁷

²⁹⁵ 18 C.F.R. § 292.303(a).

²⁹⁶ See 16 U.S.C. § 824a-3(m); 18 C.F.R. § 292.303(d).

²⁹⁷ See *FLS Energy, et al.*, 157 FERC ¶ 61,211, at P 21 (2016) (citing 18 C.F.R. § 292.303(a)).

In Order No. 69, however, FERC acknowledged the possibility that a utility might be long on capacity or energy and explained that:

A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load.²⁹⁸

FERC has since issued multiple decisions that support a purchase rate of zero for excess QF capacity (as distinct from excess energy).²⁹⁹ In *City of Ketchikan*, FERC explained that an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity.³⁰⁰ Thus, "while utilities may have an obligation under PURPA to purchase from a QF, that obligation does not require a utility to pay for capacity that it does not need In short, [respondent] seeks payment for capacity from [the] proposed

project, regardless of whether [the] capacity is needed. This is not required by PURPA or our regulations."³⁰¹

Likewise, in *Hydrodynamics*, FERC confirmed that avoided cost rates need not include the cost for capacity in the event that the utility's demand (or need) for capacity is zero—that is, "when the demand for capacity is zero, the cost for capacity may also be zero."³⁰²

Despite this precedent, FERC has never issued a decision that applies the same analysis to approve a purchase rate of zero for excess QF energy. Moreover, FERC explicitly declined to do so in its denial of a petition for declaratory order filed by NorthWestern Corporation ("NorthWestern").³⁰³ In that proceeding, NorthWestern sought relief from a dispute with the Montana Public Utility Commission (the "Montana PUC") and requested a declaratory order determining that: "(1) in periods when NorthWestern has excess generation and cannot back down its generation, the avoided cost for energy from [QFs] should be zero; and (2) nothing in PURPA, including the rule against 'non-discrimination' in pricing of avoided cost, permits the establishment of a rate in excess of a utility's avoided costs."³⁰⁴

298 Order No. 69, 45 FR at 12219.

299 See, e.g., *City of Ketchikan, Alaska, et al.*, 94 FERC ¶ 61,293 (2001) ("*City of Ketchikan*"); *Hydrodynamics, Inc., et al.*, 146 FERC ¶ 61,193 (2014) ("*Hydrodynamics*").

300 See *City of Ketchikan*, 94 FERC ¶ 61,293 at 62,062.

301 *Id.* (citing *Conn. Light and Power Co.*, 70 FERC ¶ 61,012, *reconsideration denied*, 71 FERC ¶ 61,035 (1995), *appeal dismissed sub nom. Niagara Mohawk Power Corp. v. FERC*, 117 F.3d 1485 (D.C. Cir. 1997) (utility not required to pay a rate in excess of its avoided cost)); see also *id.* at 62,062 & n.16 ("The Commission has recognized, that as time has passed since the passage of PURPA, the need to ensure that the states are using procedures which will assure that QF rates do not exceed avoided costs has become more critical.") (citations omitted).

302 *Hydrodynamics*, 146 FERC ¶ 61,193 at P 35; see also PURPA NOPR at P 87 & n.135 ("The Commission notes that, while QFs not awarded a contract pursuant to an RFP would retain their existing PURPA right to sell energy as available to the electric utility, if the state has concluded that such QF puts tendered after an RFP was held are 'not needed,' the capacity rate may be zero because an electric utility is not required to pay a capacity rate for such puts if they are not needed.').

303 See *NorthWestern Corp.*, 170 FERC ¶ 61,266 (2020).

304 *Id.* at P 1.

Specifically, Northwestern’s petition described a scenario in which it would be “long on energy and no assets in its portfolio can be backed down because of partner contracts or reliability requirements that make the resources ‘must-run,’ and Northwestern must sell the energy into the market in order to ensure that its portfolio is balanced with the load.”³⁰⁵ NorthWestern argued that this zero valuation complies with FERC’s finding in Order No. 69 that, when a QF “seek[s] to make a utility purchase more energy or capacity than the utility requires to meet its total system load[,] . . . the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load.”³⁰⁶ The Montana PUC argued instead that “a more comprehensive reading of Order No. 69 suggests a non-zero avoided cost ‘at any given time’ unless the utility’s highest-cost economically-dispatched generating unit has a variable cost of zero or incremental energy from QFs causes the utility to shut down all of its own generating units.”³⁰⁷ The Montana PUC also argued that, because NorthWestern had not valued its own resources with the excess-generation scenario adjustment, it would be discriminatory to apply it only to QFs.³⁰⁸

Ultimately, FERC concluded that more concrete facts were necessary to determine “whether and when” avoided costs can be set at zero.³⁰⁹ FERC noted, for example, that NorthWestern did not provide sufficient information about: (1) whether the other resources were truly “must run,” among other concerns; (2) when and for how long the designation allowing for reduced avoided costs pricing would exist; (3) the estimated MW involved; (4) how NorthWestern would attribute excess generation scenarios to QFs, as opposed to other generation; and (5) whether NorthWestern’s request for guidance pertained to as-available avoided cost rates, long-term fixed avoided cost rates, or both.³¹⁰ FERC exercised its discretion accordingly, and declined to address NorthWestern’s petition or any of the arguments raised therein.³¹¹ As this rejection of the Northwestern petition was based on a determination that supporting information was insufficient, it does not appear to foreclose a future determination that avoided energy costs may be zero (or perhaps even negative), at least for short-term, as-available energy provided by QFs, under properly supported circumstances.

305 *Id.* at P 2 (citations omitted).

306 *Id.* (citations and quotations omitted).

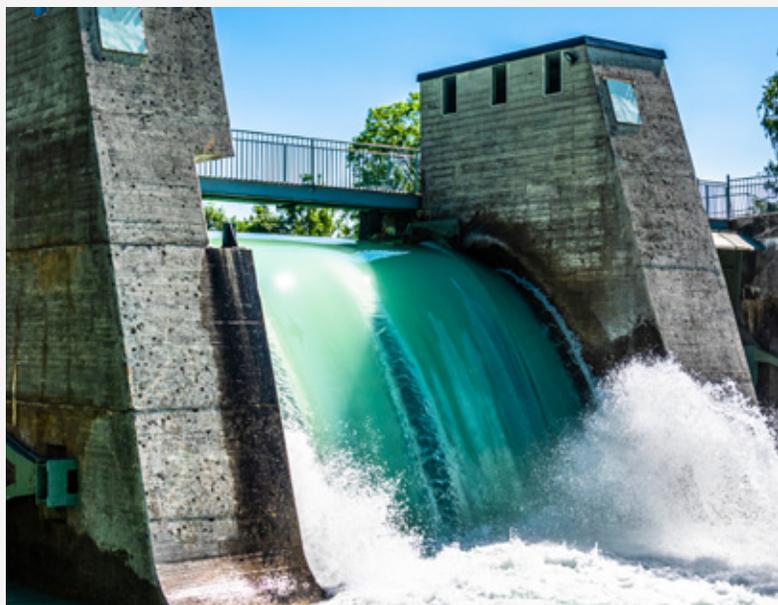
307 *Id.* at P 3 (citations and quotations omitted).

308 *Id.*

309 *Id.* at P 11.

310 *Id.*

311 *Id.*



9. FULL OR PARTIAL REQUIREMENTS CUSTOMERS

If one electric utility is an all-requirements power customer of another electric utility, such as, for example, a municipal joint action agency or rural electric cooperative, the customer utility's avoided cost rate is equal to the supplying utility's avoided cost rate. FERC first made this determination in Order No. 69,³¹² and it has consistently followed this principle in its case law.³¹³ FERC's reasoning behind this determination is that it is the supplying utility that avoids the generation costs or purchased power costs when the all-requirements utility purchases power from a QF. In describing the rationale for this policy in Order No. 69, FERC explained "[a]s the level of purchase by the all-requirements utility decreases, the supplying utility's fixed costs will have to be allocated over a smaller number of units of output."³¹⁴

In *Carolina Power & Light Co.*, FERC rejected as "without merit" an argument that a customer was not a "full requirements" customer, because the customer in that proceeding had access to its own supply resources, which, in that case, consisted of the customer's own generation facilities.³¹⁵ Rather, FERC stated that "the customer's ownership of generation is not dispositive of the character of service the utility provides."³¹⁶

Consistent with the PURPA regulations, an electric utility's status as an all-requirements customer does not limit its ability to negotiate a rate for purchase that differs from the utility's avoided cost rate.³¹⁷ However, such a negotiated rate is the prerogative of the interconnecting host utility, not the QF, and the all-requirements utility is not obligated to offer a QF a purchase price that exceeds its supplying utility's avoided cost rate.



³¹² Order No. 69, 45 FR at 12219.

³¹³ See, e.g., *W. Farmers Elec. Coop.*, 115 FERC ¶ 61,323, at P 27 (2006); *Roger & Emma Wahl v. Allamakee-Clayton Elec. Coop.*, 115 FERC ¶ 61,318, at P 10 (2006); *City of Longmont*, 39 FERC ¶ 61,301, at 61,974 (1987).

³¹⁴ Order No. 69, 45 FR at 12219. See also *W. Farmers Elec. Coop.*, 115 FERC ¶ 61,323 at P 27; *City of Longmont*, 39 FERC at 61,974. It is worth noting that FERC's policy with respect to the avoided costs of requirements customers is in alignment with its policies regarding the assumption and waiver of the PURPA purchase obligation, which are discussed in more detail *infra* at Section II.F.2.

³¹⁵ *Carolina Power & Light Co.*, 48 FERC ¶ 61,101, at 61,389 (1989); but see *N. Little Rock Cogeneration, L.P. and Power Sys. Ltd. v. Entergy Servs., Inc. and Ark. Power & Light Co.*, 72 FERC ¶ 61,263, at 62,173-74 (1995) (explaining that its orders "address only a situation involving full requirements customers and do not establish or prohibit any particular rate treatment for partial requirements sales").

³¹⁶ *Carolina Power & Light Co.*, 48 FERC at 61,389; see also *Seminole Elec. Coop., Inc., et al.*, 39 FERC ¶ 61,354, at 62,111 & n.2 (1987) (approving a partial waiver, including a provision that energy and capacity would be purchased at Seminole's avoided cost, even though some Seminole members participating in the waiver purchased power from the Southeastern Power Administration and Oglethorpe Power Corporation).

³¹⁷ See, e.g., *Pub. Serv. Co. of N.H. v. N.H. Elec. Coop., Inc.*, 85 FERC ¶ 61,044, at 61,133 (1998).

10. NEGOTIATED RATES OR TERMS

Despite PURPA's emphasis on avoided cost rates, FERC's regulations acknowledge the ability of electric utilities and QFs to negotiate rates and terms applicable to service by QFs. Specifically, 18 C.F.R. § 292.301(b) confirms that "[n]othing in this subpart . . . [l]imits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required."

11. RENEWABLE ENERGY CREDITS

Electric utilities entering into an agreement to purchase energy and capacity products from a small power production QF will often desire to obtain the "green attributes," often in the form of renewable energy credits ("RECs") associated with the resource. However, RECs do not fall under PURPA. As FERC has explained, "states have the authority to determine who owns RECs in the initial instance and how they are transferred, and has explained that the automatic transfer of RECs within a sale of power at wholesale must find its authority in state law, not PURPA." FERC has also made clear that the compensation paid to a QF at an avoided cost rate is for energy and capacity, which is separate from a REC.



E. LEGALLY ENFORCEABLE OBLIGATIONS AND CONTRACTING ISSUES

1. LEGALLY ENFORCEABLE OBLIGATIONS

Under section 292.304(d)(1), a QF has two options when it chooses to sell its output to an electric utility, the second of which is to:

[P]rovide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, except as provided in paragraph (d)(2) of this section,³¹⁸ be based on either:

- (i) The avoided costs calculated at the time of delivery; or
- (ii) The avoided costs calculated at the time the obligation is incurred.³¹⁹

A LEO is the obligation on the part of an interconnected utility to purchase the output of a QF. When a QF commits to sell to an electric utility, the QF also commits the electric utility to buy from the QF, resulting in either a contract or in a non-contractual,

binding, LEO.³²⁰ Thus, a LEO is formed based on a QF's commitment to make energy and capacity sales to an electric utility, consistent with state law and/or requirements established by nonregulated electric utilities, rather than based on any action by the utility.³²¹ A LEO "is broader than simply a contract between an electric utility and a QF"; it "is used to prevent an electric utility from avoiding its PURPA obligations by refusing to sign a contract, or . . . delaying the signing of a contract, so that a later and lower avoided cost is applicable."³²²

The determination of whether a LEO exists is a matter reserved for the states to be made by a state regulatory authority or by a nonregulated electric utility.³²³ In Order No. 688-A, FERC explained that "in the division of responsibilities of administering PURPA between this Commission and state regulatory authorities (and nonregulated electric utilities), it is the state regulatory authorities (or nonregulated electric utilities) that determine whether and when a legally enforceable obligation is created, and the procedures for obtaining approval of such an obligation."³²⁴

³¹⁸ Paragraph (d)(2) provides that "a state regulatory authority or nonregulated electric utility may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery." 18 C.F.R. § 292.304(d)(2).

³¹⁹ 18 C.F.R. § 292.304(d)(1). As explained above, a QF may also sell its output to an electric utility on an "as available" basis.

³²⁰ See *JD Wind 1, LLC, et al.*, 129 FERC ¶ 61,148, at P 25 (2009) (citations omitted), *reh'g denied*, 130 FERC ¶ 61,127 (2010) (citing Order No. 688 at P 212).

³²¹ *JD Wind 1, LLC*, 129 FERC ¶ 61,148 at P 25; see also *FLS Energy, LLC et al.*, 157 FERC ¶ 61,211, at P 24 (2016) ("*FLS Energy*").

³²² *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006, at P 36 (2011) ("*Cedar Creek*").

³²³ *Va. Elec. and Power Co.*, 151 FERC ¶ 61,038, at P 26 (2015) ("*VEPCO*"); see also Order No. 688-A at P 138 ("Whether a contract or obligation exists would depend on state law.").

³²⁴ *Id.* at P 139.

FERC “may consider claims by a QF on a case-by-case basis that the QF has created a legally enforceable obligation under state law or pursuant to other proceedings.”³²⁵ While FERC has not established specific criteria for determining when a LEO may be established, Commission precedent provides some idea of what will and will not be considered to create a LEO between a QF and a utility. A LEO can be formed before a formal contract is signed,³²⁶ and, in fact, FERC has determined that requiring a fully-executed contract or PPA as a condition precedent to creating a LEO is inconsistent with PURPA.³²⁷ A QF is entitled to a LEO where a utility has refused to negotiate a contract.³²⁸

FERC has also determined that requiring pre-conditions to creating a LEO is inconsistent with PURPA where the pre-conditions are “likely beyond the control of a QF or procedural requirements that do not reveal the likelihood that a QF will be developed and are therefore inappropriate obstacles to QF development.”³²⁹ For example, a requirement for a facilities study or a generator interconnection agreement (“GIA”) as a prerequisite for a LEO is not consistent with PURPA, because a “utility can delay

the facilities study or delay tendering an executable interconnection agreement,”³³⁰ making it no different than requiring a QF to sign a contract to form a LEO.³³¹ Likewise, requiring a QF to file a complaint with a state regulatory authority³³² is not a permitted pre-condition. The U.S. Court of Appeals for the Fifth Circuit has also determined that a utility may not limit LEOs to only QFs that are able to supply firm power,³³³ nor can a utility require a QF to deliver power within a set time frame.³³⁴ Requiring participation in a competitive solicitation process as a pre-requisite to forming a LEO has also been deemed impermissible under PURPA, as it creates “an unreasonable obstacle to obtaining a legally enforceable obligation particularly where . . . such competitive solicitations are not regularly held.”³³⁵

FERC has determined that a LEO is not created based on self-certification alone where “there is no evidence that [state law or a relevant nonregulated electric utility] provides that submitting a notice of self-certification to [FERC] is sufficient to create a [LEO], or to initiate a proceeding to establish such an obligation.”³³⁶

325 *VEPCO*, 151 FERC ¶ 61,038 at P 26 (citing Order No. 688-A at P 139).

326 *Grouse Creek Wind Park, LLC and Grouse Creek Wind Park II, LLC*, 142 FERC ¶ 61,187, at P 40 (2013) (“*Grouse Creek*”); *Murphy Flat Power, LLC, et al.*, 141 FERC ¶ 61,145, at P 24 (2012).

327 *Cedar Creek*, 137 FERC ¶ 61,006 at P 35; see also *FLS Energy*, 157 FERC ¶ 61,211 at P 23.

328 *Id.*

329 Order No. 872-A at P 386.

330 *FLS Energy*, 157 FERC ¶ 61,211 at P 20.

331 *Id.* at P 26.

332 See, e.g., *Grouse Creek*, 142 FERC ¶ 61,187 at P 40.

333 *Exelon Wind 1, L.L.C. v. Nelson*, 766 F.3d 380, 400 (5th Cir. 2014).

334 *Power Res. Grp., Inc. v. Pub. Util. Comm’n of Tex.*, 422 F.3d 231 (5th Cir. 2005).

335 *Hydrodynamics Inc., et al.*, 146 FERC ¶ 61,193, at P 32 (2014). As discussed elsewhere, Order No. 872 confirmed that states and nonregulated electric utilities may require participation in a competitive solicitation or RFP process as a prerequisite to a QF making energy and/or capacity sales to an electric utility, but only on specific conditions. See Section II.D.6.

336 See *Neb. Pub. Power Dist.*, 156 FERC ¶ 61,043, at P 23 (2016).

2. COMMERCIAL VIABILITY AND FINANCIAL COMMITMENT CRITERIA

In order to be eligible for a LEO, QFs must show that they are commercially viable and make certain financial commitments to construct the proposed project.³³⁷ Specifically, through Order No. 872, FERC added the following language as section 292.304(d)(3) of its regulations:

Obtaining a legally enforceable obligation. A qualifying facility must demonstrate commercial viability and financial commitment to construct its facility pursuant to criteria determined by the state regulatory authority or nonregulated electric utility as a prerequisite to a qualifying facility obtaining a legally enforceable obligation. Such criteria must be objective and reasonable.³³⁸

The purpose of this showing is to “ensure that no electric utility obligation is triggered for those QF projects that are not sufficiently advanced in their development, and therefore, for which it would be unreasonable for a utility to include in its resources planning.”³³⁹

Thus, states and nonregulated electric utilities may adopt “objective, reasonable” criteria to evaluate whether a proposed QF is commercially viable and has the financial ability to proceed to development such that the QF is entitled to make long-term energy and capacity sales to an electric utility pursuant to a LEO.³⁴⁰ FERC has provided states and nonregulated electric utilities with flexibility to determine what an acceptable showing of commercial viability and financial commitment must look like, so long as the criteria are objective and reasonable.³⁴¹

Examples of factors that FERC has stated would support a finding of commercial viability and financial commitment include:

- The QF took “meaningful steps to obtain site control adequate to commence construction of the project at the proposed location.”
- The QF filed an application to interconnect with the appropriate entity.
- The QF has submitted all applications, including filing fees, to obtain necessary local permitting and zoning approvals.³⁴²

³³⁷ See Order No. 872 at P 684.

³³⁸ *Id.*, Appendix at P 6.

³³⁹ Order No. 872 at P 684.

³⁴⁰ *Id.*

³⁴¹ *Id.*

³⁴² *Id.* at P 685.

Such factors must be within the QF's control.³⁴³ For example, when determining whether the QF is commercially viable, the state's or nonregulated electric utility's criteria may consider that the QF is in the process of obtaining site control or has applied for local permitting and zoning approvals, but there cannot be a requirement that the QF show that it has actually obtained site control or secured the required permitting and zoning, as those factors are outside of the QF's control.³⁴⁴ Further, states and nonregulated electric utilities cannot require a QF to have a PPA or have secured financing in order to show proof of financial commitment sufficient to create a LEO.³⁴⁵ States and nonregulated electric utilities can, however, require a showing that permitting and zoning applications have been submitted to the relevant regulatory bodies and application fees have been paid.³⁴⁶

3. POWER PURCHASE AGREEMENTS AND LEGAL ISSUES TO CONSIDER IN QUALIFYING FACILITY PURCHASES

While utilities enter into PPAs with multiple types of generators, there are certain issues specific to PPAs with QFs that FERC and state regulatory authorities have addressed.

One issue to consider is what happens when a long-term existing contract with a QF expires. In that situation, a utility would presumably still have a LEO to purchase from the QF at the utility's determined avoided cost and the obligation to sell to the QF. The QF could determine it wants to switch to making power

available on an "as available" basis, pursuant to the ongoing LEO, rather than pursuant to a new or extended contract. The LEO remains in place unless and until the utility seeks and is granted applicable FERC waivers of its obligation to purchase from, and/or its obligation to sell to, the QF, or the QF chooses to stop selling to the utility. The utility and QF are free to negotiate a new contract, if they so desire.

FERC has also considered the situation where a utility sought to put conditions on a PPA that may be permissible under a PPA with other types of generators, but that may be inconsistent with PURPA in the context of a PPA with a QF. In *Pioneer Wind Park*,³⁴⁷ Pioneer Wind Park I, LLC ("Pioneer Wind") filed a petition requesting that FERC issue an order finding that PacifiCorp's refusal to execute a PPA with Pioneer Wind unless Pioneer Wind agreed to allow PacifiCorp to curtail the Pioneer Wind project ahead of other generators, as if it were a non-firm transmission customer, was inconsistent with PURPA regulations. FERC determined that this provision was inconsistent with PURPA because Pioneer Wind and PacifiCorp intended to enter into a long-term, fixed rate PPA, which would be based on avoided costs calculated at the time PacifiCorp's obligation was incurred, rather than a sale from Pioneer Wind to PacifiCorp on an "as available basis."³⁴⁸ When a utility and a QF have entered into a PPA with a fixed rate, the utility does not have the option to curtail a QF's output; rather, it may only curtail output during a system emergency under these circumstances.³⁴⁹

³⁴³ *Id.*

³⁴⁴ *Id.*

³⁴⁵ *Id.* at P 687.

³⁴⁶ *Id.* at P 686.

³⁴⁷ 145 FERC ¶ 61,215 (2013).

³⁴⁸ *Id.* at P 36.

³⁴⁹ *Id.* (explaining that QF output is curtailable in two circumstances, including system emergencies under section 292.307(b) of FERC's regulations and in light load periods, as contemplated in section 292.304(f) of the regulations, if the QF is selling on an as-available basis); see also 18 C.F.R. § 292.304(f); Order No. 69, 45 FR at 12230.

On the state level, the Pennsylvania Public Utility Commission (the "Pennsylvania PUC") addressed a request from Pennsylvania Electric Company ("Penelec") for approval of termination of a PPA entered into pursuant to PURPA due to changed economic circumstances in the wholesale electricity market.³⁵⁰ Penelec based its request to terminate its PPA with Scrubgrass Generating Co. ("Scrubgrass") in part on changes in the wholesale market due to the PJM reliability pricing model base residual auction for determining capacity prices. Penelec also explained that "the changing economics of the Scrubgrass facility, and the wholesale power markets generally, have made it necessary for Penelec and Scrubgrass to terminate the current contractual arrangement under the PPA."³⁵¹ The Pennsylvania PUC explained that it has approved a similar request "based on representations by the parties that current market prices for electricity are lower than the contract rates in the PPA and that termination of the agreement will result in a reduction of energy costs that are ultimately paid for by ratepayers."³⁵² The Pennsylvania PUC approved the Penelec petition as "fair and reasonable termination of a longstanding contractual arrangement that no longer makes economic sense in the current wholesale electric market environment."³⁵³ The Pennsylvania PUC also granted a similar requested filed by Penelec to terminate

its contract with Piney Creek, another QF owner.³⁵⁴

Certain states also require utilities to file form contract PPAs to be used for contracting with QFs. Under the South Carolina Code, section 58-41-20 (A), the South Carolina Public Service Commission ("South Carolina PSC") will "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."³⁵⁵ Every two years, the South Carolina PSC will approve each electric utility's form contract PPAs, including "one or more standard form power purchase agreements for use for qualifying small power production facilities not eligible for the standard offer."³⁵⁶ Section 58-41-20 provides that the form contract PPAs shall include, but not be limited to, the provisions for "force majeure, indemnification, choice of venue, and confidentiality provisions and other such terms, but shall not be determinative of price or length of the power purchase agreement."³⁵⁷ The South Carolina PSC may approve multiple form contract PPAs in order "to accommodate various generation technologies and other project-specific characteristics."³⁵⁸ Section 58-41-20 does not "restrict the right of parties to enter into power

350 See Petition of Pennsylvania Elec. Co. Requesting Approval of the Termination of the Power Purchase Agreement with Scrubgrass Generating Co., No. P-2014-2400828, 2014 WL 769431 (PA P.U.C. Feb. 20, 2014).

351 *Id.* at *2.

352 *Id.* at *5.

353 *Id.*

354 Petition of Pennsylvania Elec. Co. Requesting Approval of the Termination of the Power Purchase Agreement with Piney Creek, L.P., No. P-2013-2390445, 2014 WL 2426986 (PA P.U.C. May 22, 2014).

355 S.C. Code Ann. § 58-41-20(A) (2019); see also In Re: S.C. Energy Freedom Act (H.3659) Proceeding to Establish Dominion Energy S.C., Incorporated Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, & Any Other Terms or Conditions Necessary (Includes Small Power Producers As Defined in 16 United States Code 796, As Amended) - S.C. Code Ann. Section 58-41-20(a), No. 2019-184-E, 2019 WL 6831523, at *1 (Dec. 9, 2019).

356 S.C. Code Ann. § 58-41-20(A).

357 *Id.*

358 *Id.*

purchase agreements with terms that differ from the commission-approved form(s).³⁵⁹ Importantly, the provision explains that the South Carolina PSC's decisions in response to the filing of the form contract PPAs must be consistent with PURPA and FERC's regulations implementing PURPA and nondiscriminatory to small power producers.

Similarly, there is a proposed section for the Missouri Code of Regulations, section 20 CSR 4240-3.155, that includes requirements for electric utilities regarding tariffs for purchasing electricity generated by small power producers and cogenerators.³⁶⁰ Under this provision, regulated electric utilities are required to "[s]ubmit a standard form contract for facilities over one hundred (100) kilowatts as the basis for tariffs for these facilities," which consider "[i]ssues such as avoided costs, losses, reliability and ability to schedule.

4. CONTRACT DURATION

FERC has not established a specific minimum or maximum contract term for contracts for a utility to purchase the output of a QF. In fact, in Order No. 872, FERC explicitly "decline[d] to specify a minimum required contract length given that is up to states to decide appropriate contract lengths in a way that accurately calculates avoided costs so as to meet all statutory requirements."³⁶¹ FERC has

explained that while its regulations do not specify a particular number of years for a LEO, the LEO should be long enough to allow QFs reasonable opportunities to attract capital from potential investors.³⁶²

FERC has noted that a LEO or a contract "is frequently referred to as a long-term transaction, when contrasted with an 'as available' sale and rate."³⁶³ While FERC has not spoken directly to the question of required contract duration, it did interpret the meaning of "long-term contract" with regard to a different PURPA provision, explaining that a contract of one year or longer may be considered a long-term contract. Section 210(m)(1)(A) of PURPA requires FERC to terminate the obligation to purchase from a QF where the QF has nondiscriminatory access to "wholesale markets for long-term sales of capacity and electric energy." In Order No. 688-A, FERC explained that "we continue to believe that contracts of a year or more are sufficiently long-term to meet the statutory requirement that there be 'wholesale markets for long-term sales of capacity and energy' within the meaning of section 210(m)(1)(A)(ii)."³⁶⁴ FERC explained that it had "for years defined long-term contracts under the [Open Access Transmission Tariff] as one year or longer," and "has treated power sales with a contract term of greater than one year to be 'long-term' for reporting purposes."³⁶⁵

³⁵⁹ *Id.*

³⁶⁰ 20 Mo. Code of State Regulations 4240-3.155 (2019).

³⁶¹ Order No. 872 at P 360.

³⁶² *Windham Solar LLC and Allco Fin. Ltd.*, 157 FERC ¶ 61,134, at P 8 (2016); see also Order No. 872 at P 695 ("QFs need a LEO in order to obtain financing to complete the project . . .").

³⁶³ Order No. 872 at P 97 & n.148.

³⁶⁴ Order No. 688-A at P 27.

³⁶⁵ *Id.* at n.17.

While FERC has not dictated a specific contract duration, certain state regulatory authorities have addressed contract term, although contract duration is not consistent from state to state:

- In 2015, the Idaho PUC granted a petition requesting that it reduce the length of prospective contracts from twenty years to two years.³⁶⁶
- The Wyoming Commission rejected a request to reduce a utility's PURPA contract term from twenty years to three years.³⁶⁷
- In 2017, North Carolina adopted PURPA legislation that reduced the mandatory PURPA contract term from fifteen years to ten years.³⁶⁸
- In 2020, the California Public Utilities Commission adopted a new standard offer contract for QFs of 20 MW or less that adopted a maximum twelve-year contract term for new QFs and a maximum seven-year contract term for existing QFs. The terms may be shorter than the maximum period at the seller's discretion.³⁶⁹

When it comes to the duration of a contract pursuant to a LEO, utilities and QF resources have competing objectives. A QF developer seeks to finance its project under a longer term contract. The longer term contract provides the developer with more certainty with regard to receiving financing and a return on investment.³⁷⁰ Utilities, on the other hand, may seek to mitigate price risk on behalf of their customers with shorter term commitments that would allow them to update the rate paid to the QF so that it never exceeds the utility's avoided cost at a particular time.³⁷¹ A twenty-year contract, for example, may lock the utility into a price that would eventually no longer match its avoided costs.³⁷² However, as described in Section II.D.2, above, Order No. 872 revised section 292.304 of FERC's regulations to allow state regulatory authorities and nonregulated electric utilities to require "rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery."³⁷³ Allowing for variable pricing during the term of a LEO or contract may mitigate some of the price risks to utility customers associated with a long-term fixed rate PPA.

366 In the Matter of Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements, 2015 WL 5002133 (Idaho P.U.C. Aug. 20, 2015).

367 In the Matter of Rocky Mountain Power for Modifications of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities, 2016 WL 3483204 (Wyo. P.S.C. June 23, 2016).

368 H.B. 589, Session Law 2017-192 (N.C. 2017).

369 Decision Adopting a New Standard Offer Contract for Qualifying Facilities of 20 Megawatts or Less Pursuant to the Public Utility Regulatory Policies Act of 1978, No. 20-05-006 (Cal. P.U.C. May 7, 2020), at section 6.1.

370 See, e.g., Order No. 872 at P 331 (summarizing comments arguing that FERC should require a minimum contract length for QFs).

371 See, e.g., *id.* at P 243 (summarizing comments addressing the concern, for example, "that longer contract terms at fixed rates would lead to payments above avoided costs") and P 254 ("[L]ong-term forecasts of avoided energy costs are inherently less accurate . . .").

372 See *id.* at 282 (summarizing comments that "long-term contracts (e.g., 20 years) using fixed avoided energy costs could create stranded costs potentially due to inaccurate projections" and "if the contract length is permitted to be flexible, the possibility of stranded costs would be significantly reduced for shorter contracts").

373 Order No. 872, Appendix at P 6; see also 18 C.F.R. § 292.304 (d)(2).

F. TERMINATION, WAIVERS, AND INTERACTION WITH MARKETS

1. TERMINATION

Under PURPA section 210(m), utilities may propose to terminate their must-purchase obligation on a case-by-case basis.³⁷⁴ Pursuant to PURPA section 210(m) and section 292.309 of FERC's PURPA regulations, electric utilities are not required to enter into a new contract or obligation to purchase electric energy from a QF if FERC finds that the QF has nondiscriminatory access to

(A) (ii) an independently administered, auction-based day-ahead and real-time wholesale market for the sale of electric energy, and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B) (i) transmission and interconnection services provided by a FERC-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords non-discriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to make long-term and short-term capacity sales and energy sales on a long-term, short-term, and real-time basis, to buyers other than the utility to which the QF is interconnected . . . ; or

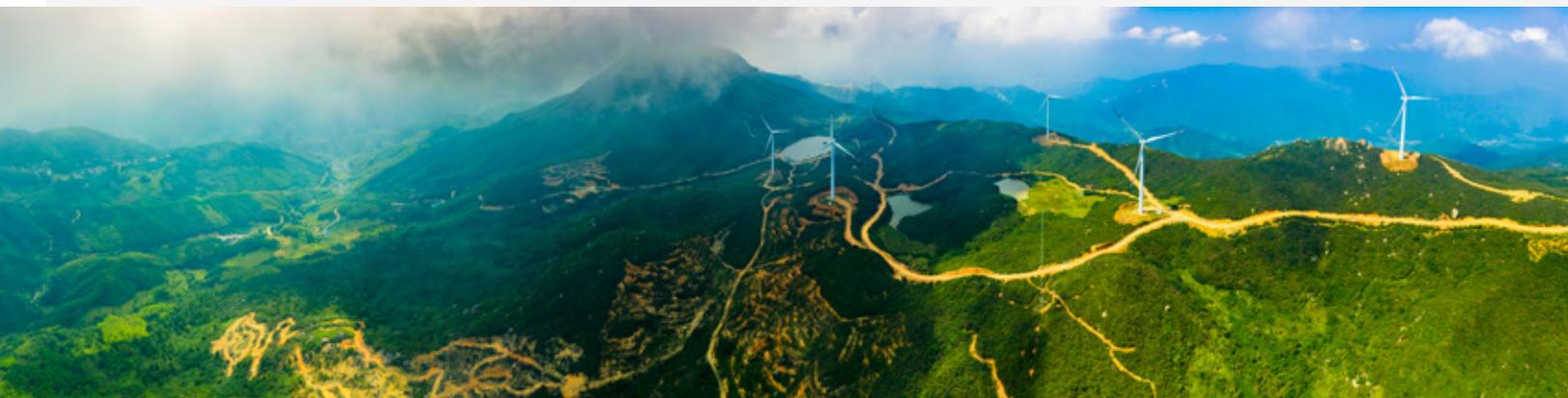
(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in (A) and (B).³⁷⁵

Under Order No. 872, utilities can also seek to justify termination of their mandatory must-purchase obligation by showing that the QF has access to RFP/competitive solicitation processes or liquid market hubs.³⁷⁶

³⁷⁴ 16 U.S.C. § 824a-3.

³⁷⁵ *Id.* at § 824a-3(1) (emphasis added).

³⁷⁶ Order No. 872 at P 659.



Each of these avenues to termination are discussed in more detail, below.

a) Organized markets

With regard to a utility's must-purchase obligation, FERC may excuse host utilities from entering into new purchase or contract obligations if there is access to a sufficiently competitive market for a QF to sell its power. Section 292.309 of FERC's regulations, implementing section 210(m) of PURPA, states that there is no new utility must-purchase obligation if FERC finds that the QF has nondiscriminatory access to competitive wholesale markets that fall into any one of the following three types of markets: (1) independently administered, auction-based day-ahead and real-time wholesale markets and wholesale markets for long-term sales of capacity and energy;³⁷⁷ or (2) a regional transmission entity with competitive wholesale markets;³⁷⁸ or (3) wholesale markets that are comparable to either of the first options.³⁷⁹ The short-hand for these three types of wholesale markets are: (1) "Day 2" markets, which are auction-based day-ahead and real-time markets with long-term energy and capacity markets (the existence of bilateral long-term energy and capacity markets suffices to meet this requirement for a Day 2 market); (2) "Day 1" markets, which

are auction-based real-time markets, but not auction-based day-ahead markets); and (3) comparable markets, respectively.

As FERC determined in Order No. 688, section 292.309(e) specifies that MISO, PJM, ISO-NE, and the NYISO provide wholesale markets that meet the statutory criteria of a Day 2 market for member utilities to qualify for relief from the mandatory must-purchase obligation.³⁸⁰ Under section 292.309(g), the CAISO and SPP satisfy the criteria for Day 1 markets, but when adopting the regulation, FERC made no specific finding as to whether the CAISO and SPP markets were sufficiently competitive as to their long-term energy and capacity markets.³⁸¹ FERC has since, however, granted requests to terminate the must-purchase obligation within SPP³⁸² and the CAISO.³⁸³ Section 292.309(f) establishes that ERCOT qualifies as a comparable market to MISO, PJM, ISO-NE, and NYISO, but likewise made no finding as to whether the long-term energy and capacity markets in ERCOT were sufficiently competitive.³⁸⁴ FERC announced in Order No. 688-A that it intended to determine on a case-by-case basis whether non-RTO/non-ISOs and RTO/ISOs that are not Day 2 markets (that is, markets that do not have both auction-based real-time and day-ahead markets) satisfy the statutory requirements for mandatory purchase requirement relief.

377 18 C.F.R. § 292.309(a)(1).

378 *Id.* at § 292.309(a)(2).

379 *Id.* at § 292.309(a)(3).

380 Order No. 688 at P 9.

381 Order No. 688 at P 11; Order No. 688-A at PP 31-39.

382 See *Xcel Energy Servs., Inc., et al.*, 122 FERC ¶ 61,048, at P 33 (2008), *reh'g denied*, 124 FERC ¶ 61,073 (2008), *appeal dismissed sub nom. John Deere Renewables, LLC v. FERC*, 2009 WL 604337 (D.C. Cir. Feb. 23, 2009) (finding "there is an active wholesale market [] in SPP, which provides QFs and potential and future QFs a meaningful opportunity to sell their electric output to purchasers other than the interconnected utility"); *Basin Elec. Power Coop.*, 162 FERC ¶ 61,209, at P 9 (2018) (granting an application to terminate the obligation to purchase electric energy or capacity from QFs with a capacity greater than 20 MW in the SPP footprint); *Neb. Pub. Power Dist.*, 156 FERC ¶ 61,043, at P 18 (2016) (same).

383 See *Pac. Gas and Elec. Co., et al.*, 135 FERC ¶ 61,234, at P 24 (2011) (granting application for termination of the mandatory purchase obligation and finding "California's market will contain competitive qualities comparable to those identified in PURPA sections 210(m)(1)(A) and (B)," so QFs will have comparable nondiscriminatory access to wholesale markets).

384 Order No. 688 at P 179.

Order No. 688 also created a rebuttable presumption that QFs of more than 20 MW in Day 2 markets have nondiscriminatory access to at least one of these competitive markets, which was reduced to 5 MW for small power production facilities (but not for cogeneration facilities) in Order No. 872.³⁸⁵ For Day 1 and comparable markets, the existence of an open access transmission tariff ("OATT") or a reciprocity tariff by a non-FERC jurisdictional transmission utility also creates a rebuttable presumption that a QF of more than 5 MW has nondiscriminatory access to competitive markets.³⁸⁶ FERC reduced the threshold to 5 MW based on the "multiple examples of small power production facilities under 20 MW participating in RTO/ISO energy markets," noting that it has found that some electric utilities have rebutted the presumption of no market access for these QFs and explaining that it had terminated their obligation to purchase from QFs below 20 MW under those

circumstances.³⁸⁷ FERC also explained that "[o]ver the last 15 years, the RTO/ISO markets have matured, market participants have gained a better understanding of the mechanics of such markets, and, as a result, we find that it is reasonable to presume that access to the RTO/ISO markets has improved and that it is appropriate to update the presumption for smaller production facilities."³⁸⁸

In order to terminate their must-purchase obligation, electric utilities must first file applications at FERC, which FERC must act on within ninety days. The procedures for requesting termination of the obligation to purchase from QFs are outlined in section 292.310 of FERC's regulations.³⁸⁹ Section 292.310 provides that utilities may seek to terminate their mandatory purchase obligation on a service territory-wide basis. An application for termination must:

385 Order No. 872 at P 625.

386 FERC's rationale for allowing termination of the must-purchase obligation where a QF has nondiscriminatory access to the markets was that RTO/ISO day-ahead and real-time markets are operated pursuant to FERC tariffs containing market rules and market mitigation aimed at preventing exercise of (excessive) market power. It is reasonable to assume these Day 2 markets are sufficiently competitive, in combination with markets for long-term contracts (including bilateral contracts) to justify the termination of the mandatory purchase obligation. Day 2 markets provide greater opportunities for QFs to make sales to a large number of buyers than the other market types because the existence of day-ahead and real-time energy markets allows all competing generators to submit bids to participate on a nondiscriminatory basis in a market from which many buyers over a large area make purchases. Capacity auctions are not required to be a Day 2 market.

387 *Id.* at P 624 (citing *Fitchburg Gas and Elec. Light Co.*, 146 FERC ¶ 61,186, at P 33 (2014); *City of Burlington, Vt.*, 145 FERC ¶ 61,121, at P 33 (2013)).

388 Order No. 872 at P 629.

389 18 C.F.R. § 292.310.



1. identify whether the applicant is seeking a finding that QFs have access to a Day 2, Day 1, or comparable market and include the factual basis upon which termination is requested including how the conditions for a Day 2, Day 1, or comparable market have been met;
2. provide sufficient notice to all potentially affected QFs;
3. identify each potentially affected QF;
4. provide transmission studies and related information, including the applicant's long-term transmission plan, transmission constraints, levels of congestion, system impact studies, information showing whether transfer capability is available, and available transfer capability information on the applicant's OASIS;
5. describe the process, procedures and practices that QFs interconnected to the applicant's system must follow to arrange for the transmission service to transfer power to purchasers other than the applicant;
6. explain any requirements and process for executing new interconnection agreements or renegotiating contracts;
7. provide a verification that the application and accurate and authentic; and
8. include a list of persons for communications.³⁹⁰

Under section 292.309(c), QFs that believe they will be impacted by an application to terminate the mandatory must-purchase obligations can attempt to rebut any

presumption of nondiscriminatory access. A QF seeking to rebut the presumption that it has nondiscriminatory access to the market may demonstrate operational characteristics or transmission constraints or other constraints that pose a barrier to its access to the market.³⁹¹ FERC regulations state that for the Day 2 and comparable markets, the QF may rebut the presumption by showing: "(1) [t]he [QF] has certain operational characteristics that effectively prevent the [QF's] participation in a market; or (2) [t]he [QF] lacks access to markets due to transmission constraints;" i.e., "[t]he qualifying facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity."³⁹² FERC has explained that "operational characteristics might include, but are not limited to: (a) highly variable thermal and electrical demand (from the QF host) on a daily basis, such that the QF cannot participate in a market; or (b) highly variable and unpredictable wholesale sales on a daily basis."³⁹³ Additionally, to rebut the presumption that a QF has nondiscriminatory access to markets in ISO-NE, NYISO, PJM, and MISO, the QF may show that it has been denied "actual access to distribution facilities for the purposes of selling power to the wholesale market."³⁹⁴ Historically, however, FERC's policy has been that a QF may not attempt to rebut the presumption of nondiscriminatory access pursuant to an OATT by raising issues related to the provision of open access transmission under the OATT.³⁹⁵ According to FERC, issues related

390 See generally 18 C.F.R. §§ 292.310 (a)-(d).

391 18 C.F.R. § 292.309(c); see also *N.Y. State Elec. & Gas Corp. and Rochester Gas and Elec. Corp.*, 130 FERC ¶ 61,216 (2010) (finding that a QF had rebutted the presumption of nondiscriminatory access to the markets due to its highly variable steam load).

392 18 C.F.R. § 309(f), (g).

393 *Entergy Servs., Inc. et al.*, 154 FERC ¶ 61,035, at P 78 (2016) (quotations omitted).

394 Order No. 688 at P 89.

395 *Id.* at P 53.

to open access implementation, including interconnection issues, should not be litigated through an electric utility's termination application, but rather through a separate complaint proceeding.³⁹⁶

In Order Nos. 872 and 872-A, FERC revised sections 292.309(c), (e), and (f) of its regulations to add a list of specific factors that small power production facilities between 5 MW and 20 MW may reference to rebut the presumption that they have nondiscriminatory access to markets.³⁹⁷ The six factors, which are non-exhaustive, are:

(1) specific barriers to connecting to the interstate transmission grid, such as excessively high costs and pancaked delivery rates; (2) the unique circumstances impacting the time/length of interconnection studies/queue to process small power QF interconnection requests; (3) a lack of affiliation with entities that participate in RTO/ISO markets; (4) a predominant purpose other than selling electricity which would warrant the small power QF being treated similarly to cogenerators (e.g., municipal solid waste facilities, biogas facilities, run-of-river hydro facilities, and non-powered dams); (5) the QF has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; and (6) the QF lacks access to markets due to transmission constraints, including that it is located in an area where

persistent transmission constraints in effect cause the QF not to have access to markets outside a persistently congested area to sell the QF output or capacity.³⁹⁸

Factors that may be used by a utility to overcome the rebuttable presumption that a QF of 5 MW or smaller lacks nondiscriminatory access to competitive markets might include the extent to which the QF has been participating in the relevant market and/or whether the QF is owned by or an affiliate of an entity that has been participating in the relevant market.³⁹⁹

Under section 292.312, a host utility may also file an application for relief from its mandatory obligation to sell. This obligation may be terminated if FERC finds that: "(1) [c]ompeting retail electric suppliers are willing and able to sell and deliver electric energy to the [QF]; and (2) [t]he electric utility is not required by state law to sell electric energy in its service territory."⁴⁰⁰ It is important to note that the test for a utility being relieved of its mandatory obligation to sell is not the same as the test for a utility being relieved of its mandatory obligation to purchase. A utility might find that it qualifies for relief from one obligation and not another. Lifting a particular utility's obligation to purchase power from a QF does not relieve the utility of its obligation to sell supplemental, back-up, standby, and maintenance power to the QF.

396 *Id.*; see also *Neb. Pub. Power Dist.*, 156 FERC ¶ 61,043 at P 21 (explaining that "the determination to grant or deny relief from a mandatory purchase requirement with respect to a particular QF is not predicated upon the existence of a currently effective GIA with an RTO, and the status of the GIA is an open access implementation issue that is irrelevant to the termination proceeding).

397 Order No. 872 at P 640.

398 *Id.* at P 641; Order No. 872-A at P 363.

399 See, e.g., 18 C.F.R. § 292.309(a) ("In determining whether a meaningful opportunity to sell exists, [FERC] shall consider, among other factors, evidence of transactions within the relevant market.").

400 18 C.F.R. §§ 292.312(b)(1), (2) (emphasis added).

When FERC grants a request to terminate the mandatory purchase obligation, the termination will only apply to new QF arrangements and not to existing contracts or legally enforceable obligations. Order No. 688-A provides that “a QF that has initiated a state PURPA proceeding that may result in a legally enforceable contract or obligation prior to the applicable electric utility filing its petition for relief pursuant to [section] 292.310 of the Commission’s regulations will be entitled to have any contract or obligation that may be established by state law grandfathered.”⁴⁰¹ However, FERC also provided that, “if a QF argues that any contract or obligation was ‘pending approval before the appropriate State regulatory authority or nonregulated electric utility,’” such that the utility’s obligation to purchase from that QF should not be terminated, FERC will consider those claims on a case-by-case basis, noting that whether a contract or a legally enforceable obligation exists depends on applicable state law.⁴⁰² In order to avoid QFs seeking to create legally enforceable obligations or enter into contracts once they have notice that a utility has filed a petition for termination, FERC will suspend the requirement for an electric utility to enter into new contracts as of the date it files its termination request under section 292.310.⁴⁰³



Unless there are changed circumstances, if a QF that has been found to have nondiscriminatory access to a specific competitive market, “this conclusion would be binding in proceedings involving the same QF and other electric utilities,” and “any subsequent state filing that a QF makes will not result in a grandfathered obligation.”⁴⁰⁴

In *Nebraska Public Power District*,⁴⁰⁵ FERC denied in part Nebraska Public Power District’s (“NPPD”) request for termination of its purchase obligation due to a PURPA purchase request pending before the NPPD Board of Directors for the Cottonwood Wind Project, LLC (“Cottonwood QF”), owned by NextEra Energy Resources, LLC (“NextEra”).⁴⁰⁶ NextEra argued that the termination should not apply to two of its projects, the Cottonwood QF and Sholes Wind, LLC (the “Sholes QF”) because it had sent letters to NPPD requesting that NPPD purchase the output of the facilities prior to the date of NPPD’s termination application, creating a legally enforceable obligation for NPPD to purchase the output of the QFs.⁴⁰⁷ NPPD argued that the purchase request for the Cottonwood QF should not be grandfathered because the project was no longer viable due to SPP’s termination of an interconnection agreement for the Cottonwood QF, thus mooted any legally enforceable obligation.⁴⁰⁸ With regard to the Sholes QF, NPPD argued that it received the purchase request after it filed its termination application, such that grandfathering was not

401 Order No. 688-A at P 137.

402 *Id.* at P 138.

403 Order No. 688 at P 228; Order No. 688-A at P 144.

404 Order No. 688-A at P 137 & n.60.

405 156 FERC ¶ 61,043 (2016).

406 *Id.* at P 2.

407 *Id.* at PP 7-8.

408 *Id.* at P 9.

warranted.⁴⁰⁹ FERC denied the termination request with regard to the Cottonwood QF, finding Cottonwood QF's application to have been grandfathered because, "by virtue of its letter to NPPD requesting an NPPD purchase, [the Cottonwood QF] has initiated a proceeding to establish a contract or legally enforceable obligation and the Cottonwood QF's application is pending approval before the applicable nonregulated electric utility," i.e., the NPPD Board.⁴¹⁰ FERC also addressed NPPD's argument that the termination of the Cottonwood QF's generator GIA with SPP, explaining that "the determination to grant or deny relief from the mandatory purchase requirement with respect to a particular QF is not predicated upon the existence of a currently effective GIA," and the status of the GIA is an open access implementation issue that is irrelevant to NPPD's termination proceeding.⁴¹¹ FERC did not grandfather the purchase request from the Sholes QF, because it was dated the same day as NPPD's termination application, relying on Order No. 688's holding that "an electric utility will not be obligated to enter into new contracts or obligations with QFs as of the date its PURPA petition is filed, and if the Commission grants the application, the mandatory purchase requirement for that electric utility ends as of the date of the PURPA petition."⁴¹²

b) Competitive solicitation processes and liquid market hubs

In Order No. 872, FERC explained that, in addition to requests to terminate the mandatory purchase obligation based on a QF's nondiscriminatory access to competitive markets, it would also consider, on a case-by-case basis, proposals to terminate the obligation based on RFPs/competitive solicitation processes or liquid market hubs.⁴¹³ The ability to terminate on this basis is rooted in the concept that competitive solicitation processes and liquid market hubs may satisfy PURPA section 210 (m)(1)(C) as comparable competitive markets.⁴¹⁴ FERC explained that whether a market is comparable to a Day 1 or Day 2 market must be determined on a case-by-case basis.

To justify termination of a must-purchase obligation based on a competitive solicitation or RFP process, FERC cited to the factors used for determining whether a competitive solicitation price can be used to set avoided cost pricing to determine whether a competitive solicitation process is conducted in a manner that would make it a comparable market for purposes of termination.⁴¹⁵ FERC stated that it will be guided by the following, non-exhaustive list of criteria for a competitive solicitation or RFP process in making this determination:

409 *Id.* at P 12.

410 *Id.* at P 20.

411 *Id.* at P 21.

412 *Id.* at P 22 (citing Order No. 688 at P 228; Order No. 688-A at P 144).

413 Order No. 872 at P 659.

414 *Id.* at P 650.

415 Order No. 872 at P 661, 413.



(A) the solicitation process is an open and transparent process that includes, but is not limited to, providing equally to all potential bidders substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality safeguards;

(B) solicitations are open to all sources, to satisfy that electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity;

(C) solicitations are conducted at regular intervals;

(D) solicitations are subject to oversight by an independent administrator; and

(E) solicitations are certified as fulfilling the above criteria by the relevant state regulatory authority or nonregulated electric utility through a post-solicitation report.⁴¹⁶

These factors will be included in section 292.304(b)(8) of FERC's regulations.

Similarly, FERC explained that it would rely on its findings in Order No. 872 with regard to the use of market hubs to determine avoided costs in considering whether liquid market hubs are comparable to Day 1 and Day 2 markets such that they can be used to justify termination of the purchase obligation.⁴¹⁷ FERC will consider the following criteria when evaluating liquid market hubs, listed at section 292.304(b)(7)(i) of the FERC regulations:

(A) whether the hub is sufficiently liquid that prices at the hub represent a competitive price;

(B) whether prices developed at the hub are sufficiently transparent;

(C) whether the electric utility has the ability to deliver power from such hub to its load, even if its load is not directly connected to the hub; and

(D) whether the hub represents an appropriate market to derive an energy price for the electric utility's purchases from the relevant qualifying facility given the electric utility's physical proximity to the hub or other factors.⁴¹⁸

⁴¹⁶ *Id.*, Appendix at P 6; see also Order No. 872 at P 413.

⁴¹⁷ Order No. 872 at P 662. In *Public Service Co. of New Mexico*, 140 FERC ¶ 61,191 (2012), prior to the issuance of Order No. 872, FERC determined that a liquid market hub was *not* sufficient to terminate the mandatory purchase obligation because it was not of comparable competitive quality to the markets identified in section 210(m)(1)(A) and (B) of PURPA. It is not clear how FERC would rule in this proceeding post-Order No. 872; however, *Public Service Co. of New Mexico* may still be useful for determining how FERC will analyze a request for termination of a must-purchase obligation based on access to a market hub.

⁴¹⁸ Order No. 872 at P 662, Appendix at P 6; see also Order No. 872 at P 190.

2. WAIVERS

Under section 292.402 of FERC's PURPA regulations, a state regulatory authority or nonregulated electric utility may seek a waiver of any requirements under Subpart C of the FERC regulations,⁴¹⁹ including, for example, the obligation to purchase from and sell to a QF. Section 292.402(b) explains that FERC will grant such a waiver only if the applicant "demonstrates that compliance with any of the requirements of subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA."⁴²⁰

Waivers are common with regard to generation and transmission ("G&T") cooperatives, public power districts, and municipal joint action agencies because they allow these entities and their members to comply with FERC's regulations in an integrated and efficient manner. Many G&T cooperatives request waiver from the obligation to make retail sales to QFs, because the distribution cooperative members of a G&T cooperative can play that role, and normally G&T cooperatives make no retail sales. The G&T cooperative may also seek a waiver to stand in place of the distribution cooperative member for the purchase

of power from QFs, committing to make the purchase on behalf of its distribution cooperative member at its own avoided cost. By the G&T cooperative standing in the shoes of its member cooperatives, and vice versa, QFs interconnecting with the G&T cooperative or its members will continue to have a market for the capacity and energy that they make available for sale and will continue to be assured a source of retail power for their operations. Essentially, the G&T cooperative and its members assume each other's roles for purchasing from and selling to QFs. FERC has granted numerous waivers of this type,⁴²¹ "where the member distribution cooperatives have assumed the G&T's sale obligation while the G&T has assumed the member distribution cooperatives' purchase obligation."⁴²²

This same structure is used by public power districts and municipal joint action agencies, for which FERC has granted waivers of a member municipality's or wholesale requirements customer's obligation to purchase power from QFs, so long as the member municipality or wholesale requirements customer makes sales to the QFs that the power district or municipal joint action agency would otherwise be required to make.⁴²³

419 18 C.F.R. § 292.402(a).

420 *Id.* at § 292.402(b).

421 See, e.g., *Associated Elec. Coop.*, 169 FERC ¶ 62,116 (2019); *Basin Elec. Power Coop.*, 160 FERC ¶ 61,078 (2017); *N.C. Elec. Membership Corp.*, 137 FERC ¶ 62,009 (2011); *W. Farmers Elec. Coop.*, 115 FERC ¶ 61,323 (2006); *Soyland Power Coop., Inc., et al.*, 50 FERC ¶ 62,072 (1990); *Seminole Elec. Coop., Inc., et al.*, 39 FERC ¶ 61,354 (1987); *Oglethorpe Power Corp., et al.*, 32 FERC ¶ 61,103 (1985), *reh'g granted in part and denied in part*, 35 FERC ¶ 61,069 (1986), *aff'd, sub nom. Greensboro Lumber Co. v. FERC*, 825 F.2d 518 (D.C. Cir. 1987).

422 *Basin Elec. Power Coop.*, 160 FERC ¶ 61,078 at P 13.

423 See, e.g., *Nebraska Pub. Power Dist.*, 162 FERC ¶ 62,072 (2018); *Mo. Joint Mun. Elec. Util. Comm'n*, 163 FERC ¶ 62,155 (2018); *Heartland Consumers Power Dist.*, 154 FERC ¶ 61,203 (2016) (granting the waiver in part for those customers who supported the waiver and denying it with regard to customers who opposed the waiver); *Mo. River Energy Servs.*, 145 FERC ¶ 62,022 (2013).

In addition to the situation where a utility will step into its members' shoes for purposes of meeting its obligations, electric utilities can also seek a waiver from the obligation to sell power if FERC finds that (1) competing retail electric suppliers are willing and able to sell and deliver electric energy to the QF, and (2) the electric utility is not required by state law to sell electric energy in its service territory (in other words, the electric utility no longer has an obligation to serve).⁴²⁴

FERC has also granted waiver in the situation where a QF seeks to require utilities to purchase capacity that would displace capacity already being used to meet the utility's needs. In *City of Ketchikan*, FERC granted a limited waiver of four utilities' obligation to purchase from a QF if the purchase would displace purchases from four state-owned hydroelectric projects (together, the "Four Dam Pool Initial Project") made by the utilities pursuant to a power sales

agreement.⁴²⁵ In granting the waiver, FERC explained that complying with the mandatory purchase obligation by purchasing power that would displace the power from the Four Dam Pool Initial Project "is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA."⁴²⁶ FERC also emphasized that PURPA does not obligate a utility "to pay for capacity that would displace its existing capacity arrangements"⁴²⁷ or "to make purchases which would result in rates which are not 'just and reasonable to electric consumers of the electric utility and in the public interest' or which exceed 'the incremental cost to the electric utility of alternative electric energy.'"⁴²⁸ FERC granted the waiver to the extent that the QF "is seeking to require utilities to purchase and pay for capacity that is not needed," but noted that it does not change the QF's rights to sell so long as the sale of capacity will not displace the sales from the Four Dam Pool Initial Project.⁴²⁹

424 16 U.S.C. § 824(a)-3(m)(5); 18 C.F.R. § 292.312.

425 *City of Ketchikan*, 94 FERC ¶ 61,293 at 62,058.

426 *Id.* at 62,061.

427 *Id.* (citing *Conn. Light and Power Co.*, 70 FERC ¶ 61,012, *reconsideration denied*, 71 FERC ¶ 61,035 (1995), *appeal dismissed*, *Niagara Mohawk Power Corp. v. FERC*, 117 F.3d 1485 (D.C. Cir. 1997)).

428 *Id.* (citing 16 U.S.C. § 824 a-3(b)).

429 *Id.* at 62,062.



3. INTERACTION OF QUALIFYING FACILITIES WITH MARKETS

There may be unique issues that arise when it comes to the interaction of QFs with markets due to the balancing between market rules and PURPA's requirements. FERC has considered whether certain market rules and requirements should apply to QFs in the same way they would apply to other generators or whether such application could disrupt what is otherwise required under PURPA. The discussion below provides examples of some issues that may arise when market rules and requirements interact with PURPA rules and regulations.

In *ISO New England Inc.*,⁴³⁰ ISO-NE proposed revisions to the Transmission, Markets, and Services Tariff to address resource dispatchability requirements.⁴³¹ Eversource Energy Service Company ("Eversource"), a host utility to QFs, protested the revisions, arguing that they: (1) would integrate QFs into the ISO-NE markets without consideration of current PURPA contracts with host utilities; (2) would "constrain the ability of QFs to determine the amount of energy available for PURPA sales"; (3) were inconsistent with the bar against a utility curtailing QF purchases without a system emergency; (4) would "allow host utilities to forgo their mandatory purchase obligations under section 210(m) of PURPA" "by allowing ISO-NE to send dispatch instructions that request QFs to not operate"; and (5) would impose additional costs that contradict the exemption of QFs from section 205 of the FPA.⁴³² FERC dismissed the arguments,

first explaining that "a QF is not obligated to participate in the ISO-NE administered energy markets and can instead choose to operate exclusively as a behind-the-meter resource on its host utility's system and not be subject to the proposed revisions."⁴³³ Further, in response to Eversource's argument that the revisions would place a constraint on how QFs are able to decide what energy they make available for PURPA sales, FERC accepted ISO-NE's response that there are options for QFs participating in ISO-NE, such as using internal bilateral transactions or identifying the host utility as the QF's owner that would allow the QFs to sell energy at a pre-determined avoided cost rate.⁴³⁴ FERC also disagreed with Eversource that the rule changes resulted in forced waiver of QF curtailment priority, citing ISO-NE's explanation that (1) resources will be dispatched "only in accordance with the physical and economic parameters specified by the resource in its energy market supply offers, and a resource owner can 'shape its offer' by submitting an offer consistent with its actual operating parameters, to communicate its level of dispatchability," and (2) that ISO-NE did not propose to curtail QFs other than in system emergencies.⁴³⁵ Therefore, FERC ultimately determined that "[g]iven ISO-NE's explanation of strategies and market mechanisms available to QFs participating in ISO-NE and ISO-NE's commitment that nothing in the proposed revisions requires QFs to register as Market Participants or compromises their protection from curtailments other than in system emergencies, we find that the proposed revisions will not compromise QF PURPA obligations and rights."⁴³⁶

430 157 FERC ¶ 61,189 (2016).

431 *Id.*

432 *Id.* at PP 11-14.

433 *Id.* at P 25.

434 *Id.* at P 26.

435 *Id.* at P 27.

436 *Id.* at P 28.

In *California Independent System Operator Corp.*,⁴³⁷ a FERC Administrative Law Judge addressed arguments that a proposal by the CAISO to apply a Control Area Gross Load billing determinant for Control Area Services would violate PURPA because it would discourage cogeneration by including retail behind-the-meter load in the allocation of the CAISO's Control Area Services costs, which would cause QFs to island.⁴³⁸ In response to that argument, the CAISO explained "that assessing behind-the-meter Loads for the Control Area Services Charge will not discourage self-generation as only Loads and exports are charged, not generation, but will bring the [grid management charge] more in line with cost causation."⁴³⁹ The Presiding Administrative Law Judge determined that

PURPA was intended to provide QFs with certain benefits, but "Congress did not intend QFs to have any rate benefit above a market rate level."⁴⁴⁰ Therefore, the Judge determined that exempting QFs' retail behind-the-meter load from the Control Area Services charge "would provide them an unfair advantage over other market participants who would not be similarly exempted from the [Control Area Services] charge in violation of [FERC] policy and congressional intent."⁴⁴¹ FERC upheld this decision, explaining that "it is reasonable to allocate the [Control Area Services] charge to all load that benefits from the service provided by the [CA]ISO," and the CAISO's proposal did not violate PURPA or FERC's PURPA regulations.⁴⁴²

437 99 FERC ¶ 63,020 (2002) ("CAISO Initial Decision"); *Opinion and Order on Initial Decision*, Opinion No. 463, 103 FERC ¶ 61,114 (2003) ("Opinion No. 463"), *order on reh'g and clarification*, Opinion No. 463-A, 106 FERC ¶ 61,032 (2004), *order denying reh'g*, Opinion No. 463-B, 113 FERC ¶ 61,135 (2005); *order denying reh'g*, Opinion No. 463-C, 116 FERC ¶ 61,224 (2006); *order denying reh'g*, 118 FERC ¶ 61,061 (2007).

438 CAISO Initial Decision at 65,123-24.

439 *Id.* at 65,124.

440 *Id.*

441 *Id.*

442 Opinion No. 463, 103 FERC ¶ 61,114 at PP 34-35.



In *Southwest Power Pool, Inc.*,⁴⁴³ SPP filed revisions to its OATT to allow it to unilaterally register resources, including Behind-the-Meter Generation of 10 MW or greater, to its Energy Imbalance Market such that the refusal or failure of a resource to register as a Market Participant would not result in exemption from SPP's registration and operational obligations.⁴⁴⁴ Further, SPP's proposed revisions would allow it to file an unexecuted Market Participant agreement with FERC if the resource was not otherwise registered by another Market Participant. According to SPP, it needed specific scheduling and supply information for each resource in its footprint to reliably operate the Energy Imbalance Market and properly account for all energy flows into and out of the transmission grid.⁴⁴⁵ FERC generally agreed with the information-gathering aspect of SPP's proposed registration requirement, but explained that, as proposed, SPP's OATT revisions could require QFs to not only register in the Energy Imbalance Market, but also require a QF to purchase from and sell power into the Energy Imbalance Market.⁴⁴⁶ As an example, FERC explained that if the QF in question failed to meet its scheduled generation level by under-generating, it could be forced to purchase power in the Energy Imbalance Market to

make up for the shortfall—a requirement that would go beyond the gathering of information needed by SPP and could violate a QF's rights under PURPA and FERC's PURPA regulations, which otherwise allow the QF to sell the net output of the facility to the interconnected utility at avoided cost rates.⁴⁴⁷ FERC found that, "[t]o the extent that SPP's proposed registration requirement triggers any charges that change what a QF recovers under PURPA's purchase obligation, as implemented by the state regulatory authority, that requirement is unjust and unreasonable."⁴⁴⁸ FERC, therefore, concluded that "SPP may not compel participation in the Energy Imbalance Market by, or otherwise trigger deviation charges for, QFs exercising their PURPA rights to deliver power to their host utilities."⁴⁴⁹ FERC required SPP to submit a compliance filing to remove QFs' obligations to actively participate in SPP's Energy Imbalance Market or to pay any charges related to registration.⁴⁵⁰

443 125 FERC ¶ 61,314 (2008), *order denying clarification*, 126 FERC ¶ 61,135 (2009).

444 *Sw. Power Pool, Inc.*, 125 FERC ¶ 61,314 at P 8.

445 *Id.* at P 35.

446 *Id.* at P 36.

447 *Id.*

448 *Id.* at P 38.

449 *Id.*

450 *Id.* at P 40.



G. INTERCONNECTION ISSUES

1. ELECTRIC UTILITY OBLIGATIONS

PURPA requires an electric utility to interconnect with a QF and to purchase from that facility any energy and capacity made available unless the utility has received an exemption from FERC allowing it to terminate its purchase obligation.⁴⁵¹ In general, the QF is responsible for paying the costs incurred to interconnect its project to the host utility.⁴⁵² The policies and procedures governing the interconnection process are contained in a series of FERC orders and have been revised over time to keep pace with the growth of small power production facilities across the nation.

Following its landmark Order No. 888,⁴⁵³ which sought to remove impediments to competition in wholesale markets and encourage the transmission of efficient, low cost power to consumers, FERC began developing rules to govern utility interconnections. FERC's interconnection processes are laid out in

Order Nos. 2003 and 2006. FERC Order No. 2003 established standard terms and conditions for interconnection service for generators of all sizes.⁴⁵⁴ A few years later, in Order No. 2006, FERC similarly adopted standardized interconnection rules, but specifically for facilities no larger than 20 MW.⁴⁵⁵ The small generator interconnection procedures detailed in Order No. 2006 were adopted to address the growing market for small power plants that can offer economic, reliability, or environmental benefits.⁴⁵⁶ Those procedures provide for a study process that can be used by any generating facility with a capacity no larger than 20 MW and two procedures that use certain technical screens to quickly identify any safety or reliability issues associated with proposed interconnections: (1) the Fast Track Process for certified facilities no larger than 2 MW; and (2) the 10 kW inverter process for certified inverter-based small generating facilities no larger than 10 kW.

451 See 18 C.F.R. §§ 292.303(a), (c); see also 18 C.F.R. §§ 292.309, 292.310.

452 See 18 C.F.R. § 292.306(a) ("Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority . . . or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis . . .").

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

454 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 804 (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 ("Order No. 2003-A"), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004) ("Order No. 2003-B"), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005) ("Order No. 2003-C"), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

455 *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 111 FERC ¶ 61,220 ("Order No. 2006"), *order on reh'g*, Order No. 2006-A, 113 FERC ¶ 61,195 (2005), *order granting clarification*, Order No. 2006-B, 116 FERC ¶ 61,046 (2006), *corrected*, 71 FR 53965 (Sept. 13, 2006).

456 Order No. 2006 at P 9.

FERC further refined its small generator interconnection procedures in 2013 to address significant penetrations of small generation, increasing requests for small generator interconnections, and the growing focus by states and others on the development of distributed resources in connection with renewable portfolio standards. One of the biggest issues facing smaller generating facilities was the

inefficiency of queue backlogs due to an increase in interconnection requests by smaller facilities. Such backlogs would often cause those smaller facilities to undergo a more costly study process when they could instead safely and reliably achieve interconnection under a Fast Track Process. In Order No. 792,⁴⁵⁷ FERC added five key features to the small generator interconnection process. The revised procedures:

1. Allow an interconnection customer to request a pre-application report from the transmission provider detailing information about system conditions at the possible point of interconnection. A utility, transmission owner, or RTO can recover the incremental cost of providing such information.
2. Include a 2 MW threshold for participation of synchronous and induction machines in the Fast Track Process. The eligibility threshold for inverter-based machines is based on the capacity of the generator and the line voltage and location of the interconnection. (Specific thresholds are set out in a chart in Order No. 792.) Under certain circumstances, inverter-based facilities up to 5 MW will be eligible for the Fast Track Process. All projects interconnecting to lines greater than 69 kV are no longer eligible for the Fast Track Process.
3. Provide for supplemental review provisions for interconnection customers that fail to meet the fast track screens (which include minimum load and other screens) to determine if a small generating facility may be interconnected safely and reliably.
4. Allow the interconnection customer an opportunity to provide written comments to the transmission provider regarding any upgrades required for interconnection.
5. Specifically include energy storage devices.

⁴⁵⁷ *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159, at P 23 (2013) ("Order No. 792"), as modified, errata notice, 146 FERC ¶ 61,019, as modified, errata notice, 148 FERC ¶ 61,215, clarified, Order No. 792-A, 146 FERC ¶ 61,214 (2014).



2. JURISDICTIONAL IMPLICATIONS

When the interconnected utility is purchasing all of a QF's output, the state regulatory authority or nonregulated electric utility has authority over the interconnection and the allocation of interconnection costs.⁴⁵⁸ Conversely, when an interconnecting utility does not purchase all of a QF's output and instead transmits the QF's power in interstate commerce for sale to a third party, FERC has jurisdiction over the rates, terms, and conditions affecting or related to such interconnected service.⁴⁵⁹ FERC's jurisdictional authority over interconnections is broad. FERC has reasoned that "[t]he fact that the facilities used to support the jurisdictional service might also be used to provide various nonjurisdictional services, such as back-up and maintenance power for a QF, does not vest state regulatory authorities with authority to regulate matters subject to the Commission's exclusive jurisdiction" that are directly or indirectly connected to their system.⁴⁶⁰

One of FERC's goals in Order Nos. 2003 and 2006 was to promote consistency

between federal and state rules governing the interconnection process by adopting a set of "best practices" that states could look to in implementing their own rules.⁴⁶¹ FERC also sought to establish a bright-line test for when its interconnection procedures would apply to a small generating facility seeking to interconnect to a host utility's distribution system. Under its "first use" test, FERC does not require the first interconnecting resource that plans to engage in sales for resale on a distribution-level system to follow the transmission provider's generator interconnection procedures.⁴⁶² The logic underlying the "first use" test is that, at the time of the request, the distribution system is not being used to transmit electric energy in interstate commerce. As a result, that initial interconnection is governed by applicable state or local law.⁴⁶³ With respect to any subsequent interconnections of resources to the same distribution system for the purpose of engaging in wholesale sales, FERC reasoned that because the distribution system is already being used to facilitate wholesale transactions, those subsequent interconnections must follow the standard generator interconnection procedures.⁴⁶⁴

⁴⁵⁸ See e.g., Order No. 2006 at P 516.

⁴⁵⁹ *Id.*

⁴⁶⁰ See *W. Mass. Elec. Co.*, 61 FERC ¶ 61,182, at 61,662 (1992), *aff'd sub nom. W. Mass. Elec. Co. v. FERC*, 165 F.3d 922, 926 (D.C. Cir. 1999).

⁴⁶¹ Order No. 2006 at P 4.

⁴⁶² See Order No. 2003-C at P 53; Order No. 2006 at P 7; *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019); see also *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,191, at P 14, *order on reh'g*, 116 FERC ¶ 61,102 (2006).

⁴⁶³ *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247, at P 92 (2020) ("Order No. 2222"), *order on reh'g*, 174 FERC ¶ 61,197 (2021) ("Order No. 2222-A").

⁴⁶⁴ *Id.* at P 93. The U.S. Court of Appeals for the District of Columbia Circuit upheld this jurisdictional application as consistent with the FPA. See *Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, 1280-82 (D.C. Cir. 2007) ("By establishing standard agreements FERC has exercised its jurisdiction over the terms of those relationships.") (citing *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667, 696 (D.C. Cir. 2000) ("FPA [section] 201 makes clear that all aspects of wholesale sales are subject to federal regulation, regardless of the facilities used.")).

While FERC has taken a broad view with respect to its jurisdiction to regulate generator interconnection procedures, it declined in Order No. 2222 to exercise such jurisdiction in connection with the integration of distributed energy resources.⁴⁶⁵ FERC did, however, note that “[i]n response to increased demand for distributed energy resource aggregations for wholesale market participation, some state or local authorities may choose to voluntarily update their distribution interconnection processes to assess the impacts of distributed energy resource aggregations on the distribution system at the initial interconnection stage, while other state and local authorities may not.”⁴⁶⁶

Later, in Order No. 2222-A, FERC reiterated that it “will not exercise jurisdiction over the interconnection to a distribution facility of a distributed energy resource for the purpose of participating in RTO/ISO markets exclusively through a distributed energy resource aggregation, even after first use has been triggered.”⁴⁶⁷ FERC did, however, grant clarification regarding its jurisdictional approach to the interconnection of QFs that participate in DER aggregations—clarifying that it will decline to exercise its jurisdiction over all interconnections of DERs to distribution facilities for the purpose of participating in RTO/ISO markets exclusively through DER

aggregation, including the interconnections of QFs.⁴⁶⁸ FERC explained that this approach will help to avoid a significant increase in the number of distribution-level QF interconnections subject to its jurisdiction, which could create uncertainty and impose a potentially overwhelming burden on RTOs/ISOs.⁴⁶⁹ However, FERC noted that if a QF DER participates in RTO/ISO markets directly, rather than exclusively through DER aggregation, then FERC’s existing QF interconnection policies will continue to apply (and it will exercise jurisdiction over a QF’s interconnection if the QF sells any of its output to an entity other than the electric utility directly interconnected with the QF).⁴⁷⁰ Finally, FERC denied requests to conduct a broader inquiry into interconnection-related issues, finding they were outside the scope of the Order No. 2222 proceeding, and declined to initiate a technical conference on simplifying the existing interconnection rules.⁴⁷¹

465 Order No. 2222 at P 96.

466 *Id.* at P 99.

467 Order No. 2222-A at P 42.

468 *Id.* at P 43

469 *Id.* at P 47.

470 *Id.*; see also *id.* at PP 44-46 (describing the Commission’s existing QF interconnection policies).

471 *Id.* at P 48.



3. COST RECOVERY ISSUES

Interconnection costs include the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative expenses incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility. These costs are understood to be in excess of the corresponding costs that the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased that energy or capacity from other sources. Interconnection costs do not include any costs used in the calculation of avoided costs.

FERC's rules for cost-recovery related to the interconnection of small generating facilities are outlined in the small GIA.⁴⁷² In addition to being responsible for paying the up-front costs associated with the actual interconnection of its project, the interconnecting customer is also responsible for costs incurred in connection with the pre-application report, supplemental reviews, system impact and facilities studies, and any network upgrades

to the extent they are required. In the event that an interconnection customer pays for upgrades, that customer may be entitled to a reimbursement of those costs over a period of time or through a crediting mechanism that offsets the customer's cost of transmission service.

For interconnections that fall under the jurisdictional authority of a state regulatory authority or nonregulated electric utility, the state or local regulatory authority generally establishes the manner of payments for interconnection costs.⁴⁷³ The costs associated with distribution-level interconnections can vary widely, and "will depend on the utility's requirements (monitoring and control equipment, system protection devices, etc.) and the cost of mitigating system violations identified by the utility."⁴⁷⁴

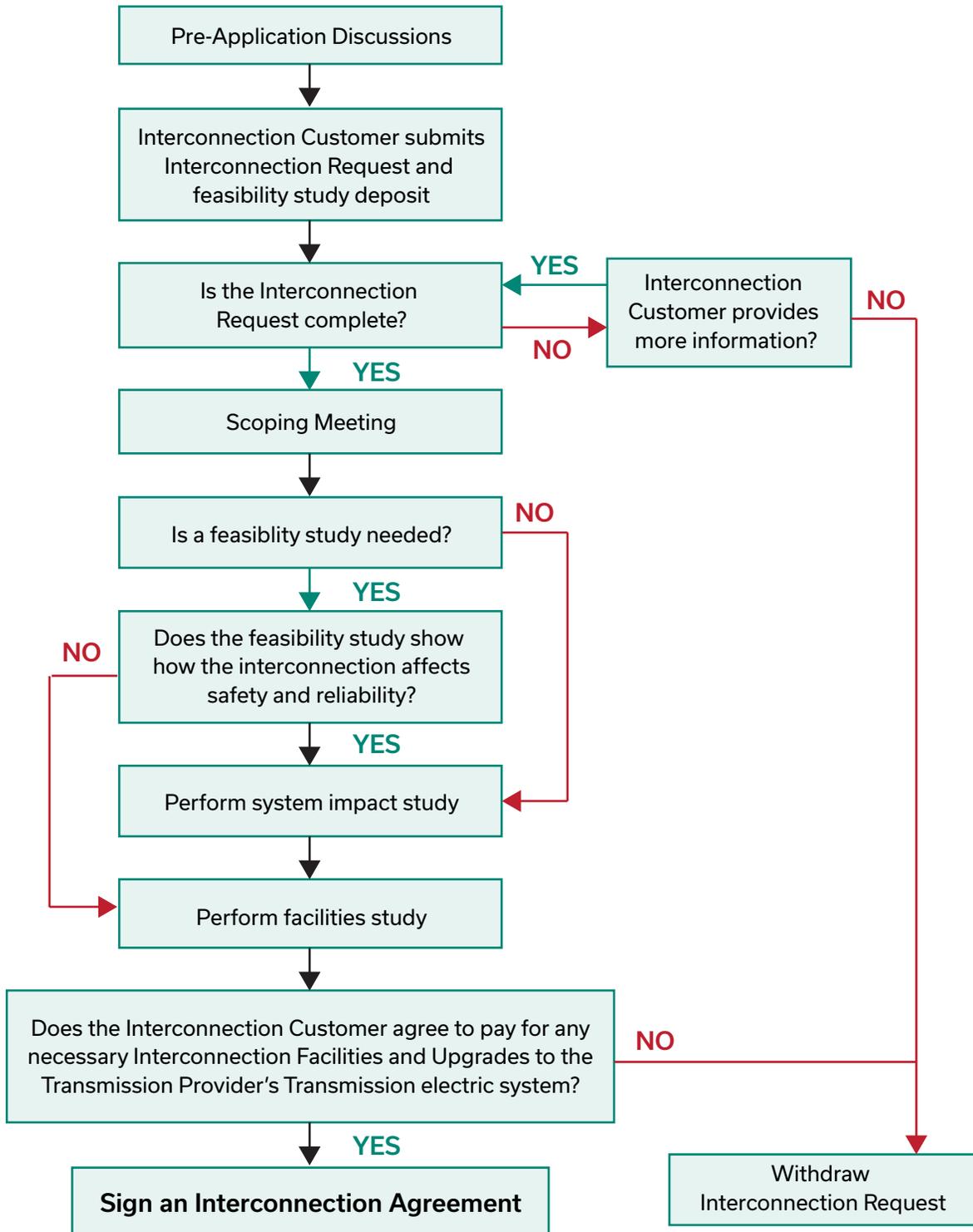


472 Order No. 2006 at Appendix F.

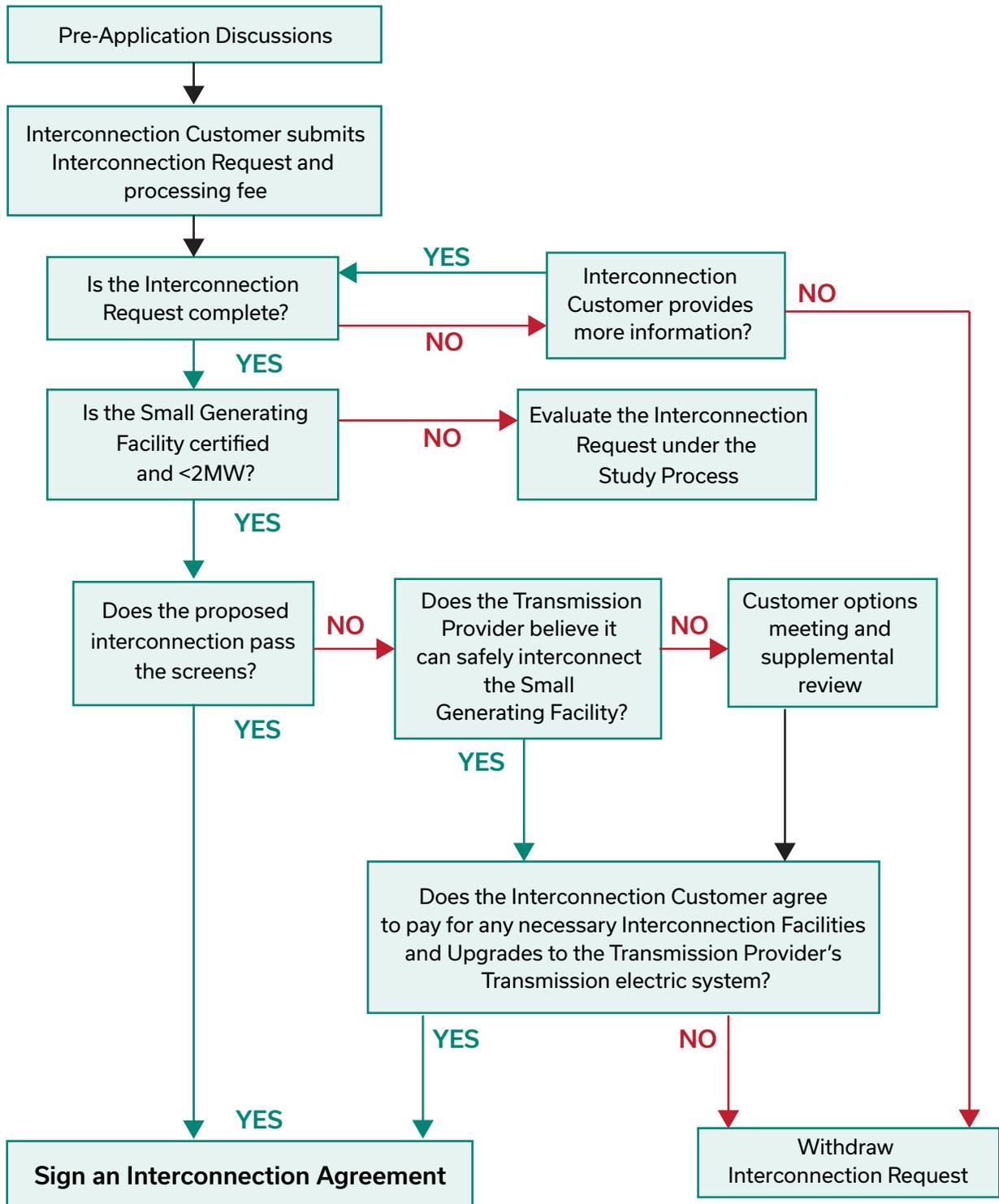
473 18 C.F.R. § 292.306(b).

474 See U.S. ENVIRONMENT PROTECTION AGENCY, INTERCONNECTION: PLUGGING RE-POWERING SITES INTO THE ELECTRIC GRID 9 (Oct. 2019), available at https://www.epa.gov/sites/production/files/2019-10/documents/interconnection_plugging_re_powering_sites_into_the_electric_grid_oct2019_508.pdf.

FLOW CHART FOR INTERCONNECTING A SMALL GENERATING FACILITY USING THE "STUDY PROCESS"



FLOW CHART FOR INTERCONNECTING A CERTIFIED SMALL GENERATING FACILITY NO LARGER THAN 2 MW USING THE "FAST TRACK PROCESS"



H. NET METERING

Net metering is a mechanism that allows retail electric consumers to offset their electric purchases by generating energy from an eligible on-site facility and delivering that energy to the distribution facilities of the consumer's local electric utility.⁴⁷⁵ While net metering does compensate for consumer energy delivered to utilities, it is completely distinct from FERC regulation of QFs under Title II of PURPA. Congress, as part of EAct 2005, amended the PURPA Title I, 111(d) standards to include net metering among a list of retail policies that states and nonregulated electric utilities are directed to consider implementing.⁴⁷⁶ Today, net metering policies reside at the state and local utility level, and net metering procedures and qualifications vary widely from state to state. Many state regulatory authorities and nonregulated electric utilities have used net metering programs as a means to compensate small renewable distributed generation, which can include generation that also qualifies as a QF under PURPA Title II. There are limits on the size of facilities that are eligible for net metering in most states. In some states, the maximum size can be as low as 10 kW, while in other states, the limit can be as high as 80 MW. Many states also have subscriber limits that cap the percentage of load that can subscribe to net metering. Other states have no such limit. There are also wide variations of limits on power capacity, often with separate limits for residential and commercial customers.

Under the Federal Power Act and PURPA Title II, FERC has jurisdiction over wholesale sales by public utilities or QFs, respectively. FERC has deemed that under net metering programs, no purchase or sale of electricity at wholesale is taking place so long as a retail customer with on-site generation is not a net supplier of energy to the grid over the applicable retail billing period.⁴⁷⁷ Therefore, until net energy is provided to the utility, FERC jurisdiction under the FPA or PURPA Title II is not triggered.

There is an ongoing debate, highlighted by a petition for declaratory order filed by the New England Rate Payers Association ("NERA") on April 14, 2020, regarding whether FERC has jurisdiction over energy sales made through net metering. The NERA petition requested that FERC (1) declare that there is exclusive federal jurisdiction over wholesale energy sales from generation sources located on the customer side of the retail meter and (2) order that the rates for such sales be priced in accordance with the FPA or PURPA as applicable.⁴⁷⁸ Those in favor of FERC exercising its authority in this area argue that net metering is a practice directly affecting wholesale rates.

⁴⁷⁵ 16 U.S.C. § 2621.

⁴⁷⁶ EAct 2005 section 1251 (amending 16 U.S.C. § 2621(d)).

⁴⁷⁷ See *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001); *Sun Edison LLC*, 129 FERC ¶ 61,146 (2009).

⁴⁷⁸ *New England Ratepayers Ass'n*, 172 FERC ¶ 61,042 (2020).

According to this position, the energy produced behind the meter that exceeds the customer's demand or is designed to bypass the customer's load is sold to the local utility for resale to the utility's other customers. The argument is that those "sales" are wholesale sales, subject to the FERC's jurisdiction, because the energy is sold to the utility's retail load or for resale in an ISO or RTO.⁴⁷⁹ Opponents of this position argue that net metering is not a sale for resale and is instead a function of retail billing, which falls under

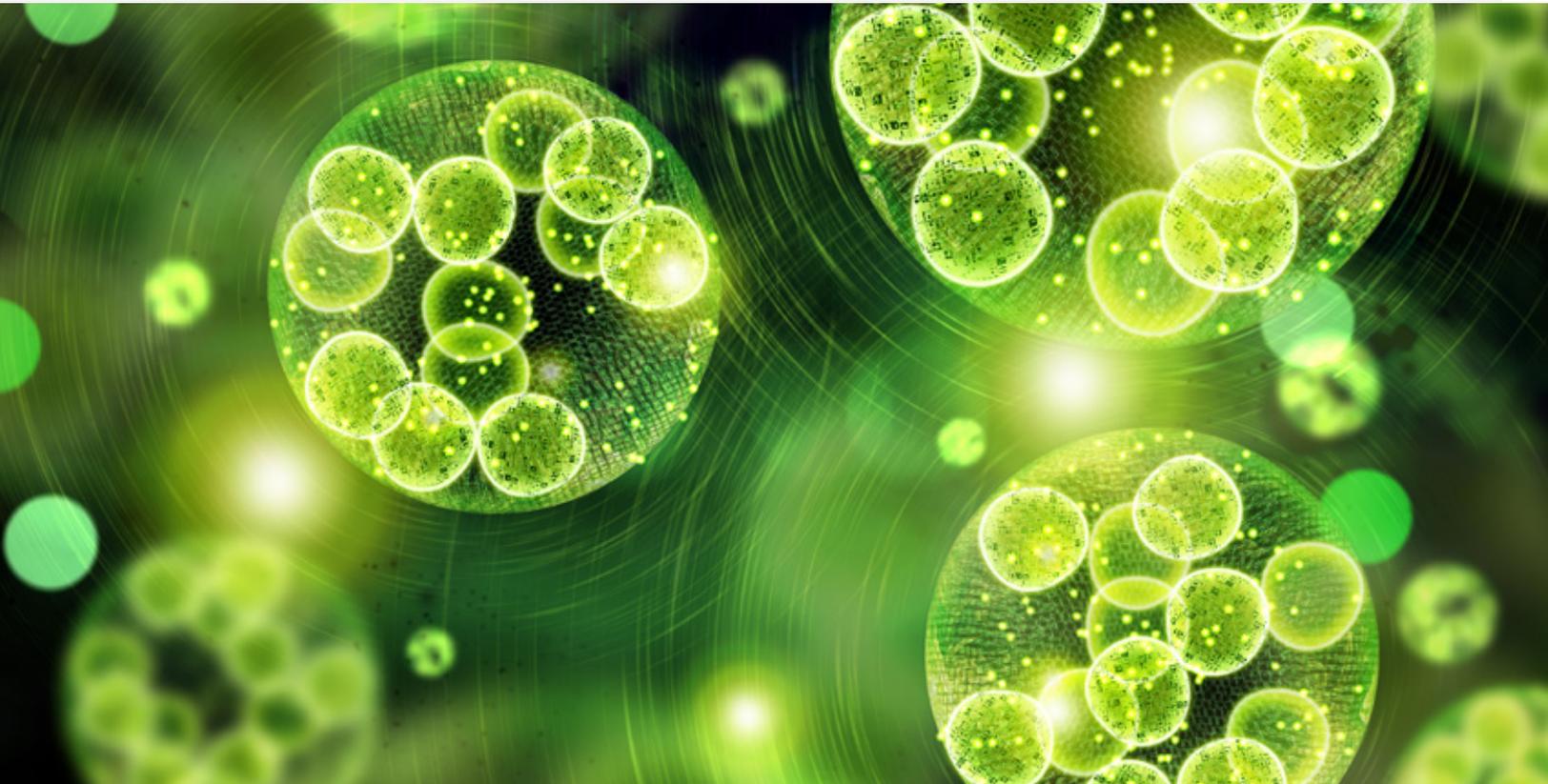
a state's jurisdiction. FERC dismissed the petition without addressing the merits of the underlying substantive issues, thereby leaving the jurisdictional question open.

As of 2020, 38 states and the District of Columbia have adopted some form of net metering, though many are trending away from the full retail rate.⁴⁸⁰ In other states, such as Texas and Idaho, net metering is offered by certain investor owned utilities.⁴⁸¹

479 *Id.* at P 4.

480 DSIRE, *Database of State Incentives for Renewables & Efficiency*, available at www.dsireusa.org.

481 *Id.* at Detailed Summary Maps - Net Metering Policies (updated June 2020).



I. FEED-IN TARIFFS

Like net metering, feed-in tariffs (“FITs”) are a state or nonregulated utility mechanism employed to encourage the investment in and deployment of renewable energy. Unlike net metering, FITs achieve these goals by offering long-term contracts to renewable energy producers. These tariffs or rates are priced per kilowatt-hour of generation “fed into” or sold to the grid. Also unlike net metering, compensation under a FIT may be an acceptable method for calculating avoided costs under PURPA.

FERC has held that, as long as a state provides QFs the opportunity to enter into long-term LEOs at avoided cost rates, a state may also have alternative programs that QFs and electric utilities may agree to participate in; such alternative programs may limit how many QFs or the total capacity of QFs that may participate in the program.⁴⁸²

An example of one such program is California’s Renewable Market Adjusting Tariff (“Re-MAT”), which provides an alternative to California’s standard PURPA avoided cost rate program. The Re-MAT program, adopted by the California Public Utilities Commission (“CPUC”) in 2012,⁴⁸³ is a FIT that provides renewable generators of less than 3 MW with a fixed-price standard contract to export electricity to California’s three large investor owned utilities.⁴⁸⁴ The general goal of the FIT

is to provide a mechanism by which small renewable generators could sell power to a utility at predefined terms and conditions. In its first iteration, the program used a Renewable Auction Mechanism (“RAM”) to determine a starting price, based on the weighted average of Pacific Gas and Electric Company’s, Southern California Edison Company’s, and San Diego Gas & Electric Company’s highest executed contract resulting from the most recent RAM auction. It then adjusted that starting price from Re-MAT according to the duration of the contract (ten-, fifteen-, twenty-year terms) and whether the generation is baseload, peaking as-available, or non-peaking as-available. QFs eligible for the FIT program were not eligible for the RAM program. In other words, smaller renewable projects (3 MW or less) that fell under FIT could not participate in the RAM.

On June 6, 2020, the CPUC initiated a rulemaking⁴⁸⁵ in response to a December 6, 2017 federal district court order⁴⁸⁶ finding that the Re-MAT program did not comply with PURPA, because it placed a 750-megawatt statewide cap on electric utilities’ collective obligation to purchase electricity from qualifying facilities, and because the prices calculated under the Re-MAT program were not permissible under PURPA. According to the court, “[p]rices generated by the Re-MAT program’s reverse auction procedure do not

482 See *Wind Creek Solar LLC*, 151 FERC ¶ 61,103, at P 6 (2015).

483 See Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program, Decision No. 12-05-035 (Cal. P.U.C. May 31, 2012).

484 See California Public Utilities Commission, *Renewable Feed-In (FIT) Program*, available at <https://www.cpuc.ca.gov/feedintariff/>.

485 Order Instituting Rulemaking To Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program, No. 18-07-003 (Cal. P.U.C. June 26, 2020) (“CPUC Re-MAT Order”).

486 *Winding Creek Solar, LLC v. Peevey*, 293 F. Supp. 3d 980, 989-90 (N.D. Cal. 2017) (“*Winding Creek I*”), *aff’d sub nom. Winding Creek Solar, LLC v. Carla Peterman, et al.*, 932 F.3d 861 (9th Cir. 2019) (“*Winding Creek II*”).

satisfy the definition of 'avoided costs' in FERC's regulations."⁴⁸⁷ The court concluded that Re-MAT's adjusting pricing mechanism "strays too far from basing prices on a utility's but-for cost," and suggested that the CPUC "look to a spot market price or similar indicator for electricity" to determine appropriate rates.⁴⁸⁸ In 2019, the Ninth Circuit affirmed the court's finding that "California's Re-MAT program violates, and is therefore preempted by, PURPA."⁴⁸⁹

In response to those orders, the CPUC suspended the Re-MAT program to consider (i) replacing Re-MAT's adjusting pricing mechanism with administratively determined prices by product category with a time-of-delivery adjustment and (ii) eliminating the bi-monthly program periods and program period caps.⁴⁹⁰ On October 16, 2020, the CPUC issued a decision⁴⁹¹ modifying aspects of the Re-MAT program to bring it into compliance with both PURPA and section 399.20 of the California Public Utilities Code. The decision adopted an electricity pricing methodology to calculate a fixed rate available to qualifying renewable generators based on the weighted average of recently-executed long-term Renewable Portfolio Standard contracts, eliminated caps on procurement during bimonthly program periods, and otherwise resumed the Re-MAT program.

Another example of a FIT program is Vermont's Standard-Offer Program, pursuant to which distribution utilities are required to buy renewable power from an eligible generator (2.2 MW or less) at a specified price for a specified period of time. Eligible projects are selected through a lottery system and receive a standard-offer contract with a price based on technology-specific avoided costs. Each year, the Vermont Public Utility Commission ("Vermont PUC") issues a request for proposals in which it specifies the annual program capacity, technology-specific allocations, and avoided-cost price caps.⁴⁹² It then makes annual capacity awards based on the lowest-priced bids.⁴⁹³ On October 9, 2020, the Vermont PUC issued an order opening its annual review process for the 2021 implementation of its Standard-Offer Program.⁴⁹⁴ As part of that Order, the Vermont PUC has asked participants to address FERC's recent revisions to PURPA under Order No. 872 and the applicability to the Standard-Offer Program.

487 *Winding Creek I*, 293 F. Supp. 3d at 989.

488 *Id.* at 990.

489 *Winding Creek II*, 932 F.3d at 865.

490 See generally CPUC Re-MAT Order.

491 See Decision Resuming and Modifying the Renewable Market Adjusting Tariff Program, No. 20-10-005 (Cal. P.U.C. Oct. 16, 2020).

492 More information on Vermont's program is available at <https://puc.vermont.gov/electric/standard-offer>.

493 *Id.*

494 *Investigation to review the 2021 implementation of the standard offer program*, Order Opening Investigation and Establishing Schedule, Case No. 20-2935-INV (Vt. P.U.C. Oct. 9, 2020).



J. OPERATIONAL ISSUES

1. SUPPLEMENTARY, BACK-UP, MAINTENANCE, AND INTERRUPTIBLE POWER

Utilities with an obligation to sell power to QFs also have an obligation to provide supplemental power, back-up power, maintenance power, and interruptible power upon request of the QF, pursuant to section 292.305 of FERC's PURPA regulations. Supplementary power means "electric energy or capacity supplied by an electric utility, regularly used by a [QF] in addition to that which the facility generates itself."⁴⁹⁵ Back-up power means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a QF's own generation equipment during an unscheduled outage of the facility.⁴⁹⁶ Maintenance power means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.⁴⁹⁷ Back-up and maintenance power together sometimes are referred to as "standby power." Interruptible power means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.⁴⁹⁸ The obligation to provide supplemental, back-up, maintenance, and interruptible power applies unless the state regulatory authority or non-regulated utility, after notice and an opportunity to be heard, waives the requirement.⁴⁹⁹ The electric utility must demonstrate and the state

regulatory authority (or non-regulated utility) must find that providing supplemental power, back-up power, maintenance power, and/or interruptible power would impair the electric utility's ability to render adequate service to its customers or would place an undue burden upon the utility.⁵⁰⁰

Under section 292.305(a)(2), rates for these services are to be based on system-wide costing principles and are to be nondiscriminatory. However, there is an additional requirement for calculating the rates for sales of back-up and maintenance power. FERC's regulations provide that these rates are not to be based upon an assumption, unless supported by factual data, that forced outages or other reductions in electric output by all QFs on an electric utility's system will occur simultaneously, or during system peak, or both.⁵⁰¹ The rate must also take into account the extent to which scheduled outages of the QF can be usefully coordinated with scheduled outages of the utility's facilities.

Some electric utility rates for standby service have been challenged as discriminatory and inconsistent with PURPA. In August 2019, Vote Solar, a California-based non-profit organization, and certain individual solar users in Farmington, New Mexico (together, "Plaintiffs") sued the City of Farmington, which operates the Farmington Electric Utility System, alleging that Standby Service Riders

495 18 C.F.R. § 292.101(b)(8).

496 *Id.* at § 292.101(b)(9).

497 *Id.* at § 292.101(b)(11).

498 *Id.* at § 292.101(b)(10).

499 18 C.F.R. § 292.305(b)(2).

500 *Id.*

501 *Id.* at § 292.305(c)(1).

for generators are inconsistent with PURPA.⁵⁰² According to Plaintiffs, Farmington's "Standby Service Riders impose higher and additional charges for customers who self-supply some of their electricity needs with their own solar generation," Farmington "lacks the requisite data showing a difference in loads and costs by solar compared to non-solar customers," Farmington did not use accurate data or consistent system-wide costing principles when determining the charges in the Standby Service Riders, and Farmington's "Standby Service Riders contain unreasonable and discriminatory charges."⁵⁰³ Plaintiffs also assert that the Standby Service Riders are in violation of FERC's rate-setting regulations and discriminate against solar users.⁵⁰⁴ The United States District Court for the District of New Mexico dismissed the case for lack of subject matter jurisdiction, finding that the Plaintiffs did not allege sufficient facts to constitute a claim under PURPA Section 201(h), and thus did not reach the merits of the allegations.⁵⁰⁵ However, it is worth noting that retail rates of this type may be challenged as discriminatory and inconsistent with PURPA.

Reforms in FERC Order Nos. 764 and 764-A,⁵⁰⁶ which were intended to promote integration of variable energy resources into the grid, required new variable energy resources to report relevant meteorological and forced outage data to transmission providers that need such data for power production forecasting. Regulated public utility transmission providers are required to offer transmission customers transmission schedules on fifteen-minute intervals within the hour. Intermittent resources, including some small power producer QFs (such as wind and solar PV that are 30 MW or smaller), are covered by these provisions. The data collected can have ramifications for system-wide costing of sales to a QF, particularly for supplemental power, but also for back-up and maintenance power, as the data establish a better basis to determine the degree to which forced outages occur simultaneously, as well as the degree to which the resources can be coordinated with scheduled outages.

⁵⁰² *Vote Solar v. City of Farmington*, 2020 WL 673087 (D. New Mexico Feb. 11, 2020), *appeal docketed* *Vote Solar v. City of Farmington*, Case No. 20-2028 (10th Cir. Mar. 9, 2020).

⁵⁰³ *Id.* at 2.

⁵⁰⁴ *Id.*

⁵⁰⁵ *Id.* at 1.

⁵⁰⁶ *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331 ("Order No. 764"), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"), *order on reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013).



2. SYSTEM EMERGENCIES AND CURTAILMENT

FERC's regulations under PURPA provide requirements for electric utilities and QFs in the case of system emergencies. A system emergency is defined in FERC's regulations as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property."⁵⁰⁷

Under section 292.307(a) of FERC's regulations, a QF is only required to provide energy or capacity to an electric utility during a system emergency under two circumstances. First, the QF will be required to provide energy or capacity during a system emergency where such provision of energy and capacity is provided for in an agreement between the QF and the electric utility.⁵⁰⁸ Second, the QF is required to provide capacity or energy during a system emergency if it is ordered under section 202(c) of the FPA.⁵⁰⁹ Section 202(c) addresses temporary connection and exchange of facilities during emergencies, such as the continuance of a war in which the United States is engaged or where there is an emergency due to a sudden increase in demand, a shortage of electric energy, fuel, or water for generating facilities, or other causes.⁵¹⁰

Further, PURPA provides for an exception to a utility's must-purchase obligation in the case of system emergencies. Under section 292.307(b) of FERC's regulations, an electric

utility may discontinue purchases from a QF if those purchases would contribute to the emergency, and it may discontinue sales to a QF, so long as it does so on a nondiscriminatory basis.⁵¹¹ Pursuant to PURPA, curtailment is only permitted during times of system emergency.⁵¹²

In addition to system emergencies, FERC allows utilities to curtail QF power during light loading situations, pursuant to section 292.304(f), so long as they are purchasing from a QF on an as-available basis, rather than pursuant to a long-term PPA.⁵¹³ Section 292.304(f) provides that purchases of energy or capacity from a QF "will not be required . . . during any period during which, due to operational circumstances, purchases from [QFs] will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself."⁵¹⁴ In Order No. 69, FERC explained that "[t]his section was intended to deal with a certain condition which can occur during light loading periods," where a utility operating only base load units would be forced to cut back the output from those units to purchase from a QF, and the base load units may not be able to ramp up quickly enough to meet later system demand.⁵¹⁵ This would cause the utility to use "less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output," resulting in the utility

⁵⁰⁷ 18 C.F.R. § 292.101(b)(4).

⁵⁰⁸ See 18 C.F.R. § 292.307(a).

⁵⁰⁹ See *id.* at § 292.307(a).

⁵¹⁰ 16 U.S.C. § 824a(c).

⁵¹¹ 18 C.F.R. § 292.307(b).

⁵¹² *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, at P 37 (2013) ("*Pioneer Wind Park I*").

⁵¹³ See Order No. 69, 45 FR at 12227-28.

⁵¹⁴ 18 C.F.R. § 292.304(f).

⁵¹⁵ Order No. 69, 45 FR at 12227.

incurring greater costs for purchasing from the QF rather than avoiding costs.⁵¹⁶ To avoid the situation where a QF would then owe a utility for these negative avoided costs, FERC instead permitted a utility to identify such periods where this situation would happen and notify the QF so that the QF would not deliver its output during that period of time.⁵¹⁷ A claim that this type of light loading would occur is subject to verification by the utility's regulatory authority before or after it occurs, and utilities must provide notice to the QF.⁵¹⁸ FERC also emphasized that this section cannot be used to "override contractual or other legally enforceable obligations incurred by the electric utility to purchase from a [QF]," hence applying the provision only to utilities purchasing from a QF on an as available basis.⁵¹⁹ This provision "cannot be relied upon to curtail purchases of unscheduled QF energy for general economic reasons."⁵²⁰

FERC precedent in this area provides examples of how the regulations are applied and when curtailment is and is not permitted. In *Pioneer Wind Park*,⁵²¹ Pioneer Wind Park I, LLC ("Pioneer Wind") filed a petition requesting that FERC issue an order finding that PacifiCorp's refusal to execute a PPA with Pioneer Wind unless Pioneer Wind agreed to allow PacifiCorp to curtail the Pioneer Wind project ahead of other generators, as if it were a non-firm transmission customer, was inconsistent with PURPA regulations, and that Pioneer Wind was entitled to network

resource interconnection service under PacifiCorp's standard Large GIA. Pioneer Wind also requested that FERC declare that an amendment filed by PacifiCorp at the Wyoming Public Service Commission ("Wyoming PSC"), which provided for higher avoided cost pricing if a QF would agree to be curtailed, would be inconsistent with PURPA and its regulations. FERC found that the proposed curtailment provision violated PURPA and its regulations. As explained, FERC's regulations only permit a purchasing utility to curtail a QF's output in two circumstances: (1) system emergencies; and (2) in light load situations, but only if the QF is selling power on an "as available basis."⁵²² However, neither circumstance was present in *Pioneer Wind Park*. Instead, Pioneer Wind and PacifiCorp intended to enter into a long-term, fixed rate PPA, based on the avoided costs calculated at the time the obligation is incurred.⁵²³ Under these circumstances, FERC found that its PURPA regulations would only allow PacifiCorp to curtail Pioneer Wind during system emergencies.⁵²⁴ Therefore, FERC declared the curtailment provisions and the amendment filed at the Wyoming PSC to be inconsistent with PURPA and its regulation.⁵²⁵

516 *Id.*

517 *Id.*

518 *Id.*

519 *Id.* at 12228.

520 *Entergy Servs., Inc.*, 137 FERC ¶ 61,199, at P 55 (2011).

521 145 FERC ¶ 61,215 (2013).

522 *Id.* at P 36.

523 *Id.*

524 *Id.*

525 *Id.* at P 39.



In *Idaho Wind Partners 1, LLC*,⁵²⁶ FERC granted a petition filed by Idaho Wind Partners ("Idaho Wind") that requested FERC to find that a proposed tariff revision filed by Idaho Power Company ("Idaho Power") with the Idaho Public Utility Commission ("Idaho PUC") would violate PURPA and the regulations implementing PURPA. Idaho Power's proposed "Schedule 74" concerned the curtailment of energy and capacity purchases from QFs, and, if approved by the Idaho PUC, would have allowed Idaho Power to curtail energy and capacity purchases during light loading situations.⁵²⁷ In its Declaratory Order, FERC explained that "a utility may not curtail unilaterally where the QF energy is purchased, as here, pursuant to a long-term obligation," noting that even if Schedule 74 had not been proposed, Idaho Power "would not have permission to curtail QF purchases under its current QF PPAs."⁵²⁸

In *Occidental Chemical Corp. v. Midwest Independent System Operator, Inc.*⁵²⁹, FERC denied a complaint filed by Occidental Chemical Corporation ("Occidental") against MISO alleging that MISO's treatment of QFs in the Entergy service territory violated PURPA.⁵³⁰ Among other issues, Occidental argued that MISO's plan to integrate QFs (the "QF Integration Plan") "improperly strips QFs of their curtailment priority ensured by 18 C.F.R. §292.307(b),"⁵³¹ because it allowed

MISO to dispatch a QF down to mitigate a constraint when there is congestion on the MISO system.⁵³² According to Occidental, "system congestion is not the type of 'system emergency' that would permit MISO to curtail QF sales pursuant to PURPA."⁵³³ FERC denied the complaint, finding that the QFs were able to maintain their curtailment priority rights under PURPA⁵³⁴ because there were "steps that QFs can take to prevent their facilities from being dispatched down (i.e., effectively curtailed), except in the event of a system emergency," and because QFs could self-schedule in MISO's real-time market, "result[ing] in the QF being able to provide whatever level of energy it chooses" and being "curtailed [only] by manual action of MISO's system operators during a system emergency."⁵³⁵

Finally, in *Southwest Power Pool, Inc.*,⁵³⁶ FERC accepted Tariff revisions proposed by SPP under which a QF's output could be curtailed "proportionately and equivalent to firm service, e.g., during a [North American Electric Reliability Corporation] [Transmission Loading Relief] level 5 event ["TLR-5 event"] or activation of an internal SPP constraint in [its Market Operating System] such as Congestion Management Event 5."⁵³⁷ According to FERC, this provision was consistent with PURPA, because a TLR-5 event is consistent with the definition of a system emergency under

526 140 FERC ¶ 61,219 (2012), *reh'g denied*, 143 FERC ¶ 61,248 (2013) ("*Idaho Wind Partners*").

527 *Idaho Wind Partners*, 140 FERC ¶ 61,219 at P 3.

528 *Id.* at P 40.

529 155 FERC ¶ 61,068, *reh'g denied*, 156 FERC ¶ 61,213 (2016) ("*Occidental*").

530 *Occidental*, 155 FERC ¶ 61,068 at P 1.

531 *Id.* at P 14.

532 *Id.* at P 10.

533 *Id.* at P 14.

534 *Id.* at P 74.

535 *Id.* at P 73.

536 140 FERC ¶ 61,225 (2012).

537 *Id.* at P 50. As described in the order, a "TLR-5" event "requires curtailment/reallocation on pro rata basis with Network Integration Transmission Service and Native Load to mitigate a System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) violation." *Id.* at n.53. A Congestion Management Event 5 "is an internal TLR level 5 to SPP's market." *Id.* at P 10.

PURPA, such that curtailing “unscheduled output at TLR level 5 on an equivalent basis with firm transmission service, for the output of QFs sold under PURPA” is appropriate.⁵³⁸

3. STANDARDS FOR OPERATING RELIABILITY

Section 292.308 of FERC’s regulations provides that state regulatory authorities and nonregulated electric utilities may implement standards for the purpose of safety and reliability of their interconnected operations. Specifically,

Any state regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.⁵³⁹

As of this writing, there is little FERC case law in this area. There are some cases that address safety and reliability more generally, but not necessarily in the context of the section 292.308 or the implementation of standards by states and nonregulated electric utilities.

In *Kern River Cogeneration Co.*,⁵⁴⁰ FERC granted a petition for declaratory order filed by Kern River Cogeneration Company (“KRCC”) requesting that FERC find that a switchyard that connects KRCC’s QF to the transmission system was part of the QF. FERC focused in part on the fact that while “PURPA defines cogeneration and small power production facilities as ‘facilities’ which ‘produce’ electric power,” and a switchyard does not produce power, “[t]he fact that the dominant function of the switchyard is to enable the QF to control the flow of electricity into and out of its facilities, which is critical to the safe and reliable operation of the power producing portions of [KRCC’s] facility, also favors [FERC’s] interpretation of section 210(a).”⁵⁴¹ FERC invoked section 292.308 of its regulations and emphasized that its holding does not preclude “a utility that is required to purchase power from a QF from operating a switchyard facility such as KRCC’s where a State commission finds such operation to be necessary to protect the safety and reliability of the utility’s system under State rules implementing Section 210 of PURPA.”⁵⁴²

538 *Id.* at P 51.

539 18 C.F.R. § 292.308.

540 31 FERC ¶ 61,183 (1985).

541 *Id.* at 61,355.

542 *Id.* at 61,356 (citing 18 C.F.R. § 292.308).

In *Entergy Services, Inc.*,⁵⁴³ Entergy Services, Inc. ("Entergy") filed revised Generator Operator Limits ("GOL") to address transmission constraints.⁵⁴⁴ In response to requests for clarification as to whether the GOL proposal would limit a QF's rights under PURPA, FERC accepted Entergy's explanation that the proposed GOL would not apply to output from QFs interconnected to the Entergy transmission grid and Entergy would pay the QF for purchases at avoided costs in excess of the QF's GOL so long as the reliability of the system was not compromised.⁵⁴⁵ While not an application of state or nonregulated electric utility operating standards imposed on a QF, FERC permitted a degree of flexibility in order to ensure reliability of the system.

At the state level, on November 19, 2019, the Arizona Corporation Commission ("ACC") issued an order adopting its proposal in a May 24, 2019 Notice of Proposed Rulemaking to add a new Article 26, "Interconnection of Distributed Generation Facilities," to 14 A.A.C. 2, with new rules applicable to Distributed Generation ("DG") Facilities (the "DGI Rules").⁵⁴⁶ Among other provisions, the DGI Rules establish standards for reliability

and safety, including mandatory technical standards, processes, and timelines for utilities to use for interconnection and parallel operation of different types of DG facilities; provisions for disconnection of DG facilities from the distribution system; specific safety requirements; and a provision regarding responsibility for damages from DG facilities operated at a higher capacity than reviewed and approved by the utility. The ACC's Utilities Division explained that the "DGI Rules would adopt standards that promote current best practices of DGI for utilities, utility distribution systems, utility customers, and customers' generating facilities and would help to ensure the continued safe and reliable operation of the distribution systems while also enhancing long-term system planning."⁵⁴⁷ Further, in setting the new rules, the ACC explained that while there has been no evidence that unauthorized field changes to Generating Facility settings, failures of power control systems, or incorrect programming of power control systems have created safety issues or other problems for customers, utilities, or the grid, it would reevaluate the situation and determine whether additional rulemaking, potentially emergency rulemaking, is necessary if such evidence arises.⁵⁴⁸

543 102 FERC ¶ 61,281.

544 *Id.* at P 1.

545 *Id.* at P 61.

546 In the Matter of the Notice of Proposed Rulemaking Regarding Interconnection of Distributed Generation Facilities, No. 77437, 2019 WL 5727382 (A.C.C. Nov. 1, 2019).

547 *Id.* at P 68.

548 *Id.* at P 97.



K. ENFORCEMENT ISSUES

Judicial review and enforcement of FERC's PURPA rules and regulations are governed by sections 210(g) and 210(h) of PURPA. There are three ways to challenge a decision as inconsistent with FERC's rules and regulations under PURPA: (1) bring a proceeding before the relevant state regulatory authority or governing body;⁵⁴⁹ (2) file for judicial review of any state regulatory proceeding in state court;⁵⁵⁰ or (3) file a petition for enforcement against the state regulatory authority or nonregulated electric utility at FERC, and, if FERC chooses not to act, file a petition against the state or nonregulated electric utility in U.S. district court.⁵⁵¹

Most PURPA implementation questions are handled by the state regulatory authorities and nonregulated electric utilities. FERC has explained that "its jurisdiction to review and enforce the section 210(f) implementation requirement (i.e., the requirement that State regulatory authorities and nonregulated electric utilities promulgate rules consistent with the requirements established by [FERC] under section 210(a) of PURPA) is not exclusive," and "that generally proceedings would be initiated at the State level."⁵⁵² So long as the issue is one of the proper interpretation or implementation of a PURPA QF regulation, then the proper forum is the state regulatory authority and/or nonregulated electric utility, pursuant to section 210(g)(1).

State regulatory authorities and nonregulated electric utilities have authority under PURPA to implement section 210 consistent with FERC's regulations. Normal state appellate procedures apply if a party wants to challenge a state or a local regulatory authority's decision or interpretation in implementing a PURPA QF regulation under section 210(g) (2). Access to FERC and the federal courts is limited to complaints that a state regulatory authority or a nonregulated electric utility, in its interpretation or implementation, did not comply with the FERC's QF regulations.

FERC has jurisdiction to enforce PURPA section 201 and 210 rules. Under PURPA section 210(h), FERC can require state regulatory authorities and nonregulated electric utilities to comply with its rules at its discretion. Under section 210(h)(2)(a), FERC has the ability to enforce its PURPA rules and regulations against state regulatory authorities and nonregulated electric utilities. Under section 210(h)(2)(B), electric utilities and QFs may petition FERC to act under section 210(h) (2)(A)⁵⁵³ to enforce the requirement that a state regulatory authority or nonregulated electric utility implement FERC's regulations. As noted, this authority is discretionary,⁵⁵⁴ and "the Commission is not required to undertake enforcement action."⁵⁵⁵

549 16 U.S.C. § 824a-3(g)(1); see also Order No. 872 at P 167.

550 16 U.S.C. § 824a-3(g)(2); see also Order No. 872 at P 167.

551 16 U.S.C. § 824a-3(h)(2)(B); see also Order No. 872 at P 167.

552 *Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utilities Act of 1978*, 23 FERC ¶ 61,304, at 61,644 (1983) ("1983 Policy Statement").

553 16 U.S.C. § 824a-3(h)(2)(A).

554 *Morgantown Energy Associates and City of New Martinsville, W. Va.*, 139 FERC ¶ 61,066, at P 44 (2012).

555 1983 Policy Statement at 61,645.

To invoke section 210(h)(2)(B), entities file a pleading styled as a “Petition for Enforcement” requesting that FERC initiate an enforcement action against the applicable state regulatory authority or nonregulated electric utility in the appropriate court. FERC may bring an action in federal court if a state regulatory authority or nonregulated electric utility fails to comply with the requirements of its rules, although it rarely does. If an electric utility or QF files a petition, and FERC does not undertake an enforcement action within sixty days of the filing, under section 210(h)(2)(A) of PURPA, the petitioner then may bring its own enforcement action directly against the state regulatory authority or nonregulated electric utility in the appropriate U.S. federal district court, and FERC may intervene as a matter of right.⁵⁵⁶

In response to a Petition for Enforcement, FERC may issue a declaratory order addressing whether a state regulatory authority or nonregulated electric utility properly complied with PURPA and FERC’s regulations, even where it does not choose to bring an enforcement action in federal court. It is within FERC’s discretion to issue a declaratory order in response to an enforcement petition “to remove uncertainty,” but it is technically outside of the enforcement regime described above under PURPA section 210(h).⁵⁵⁷ As described by FERC, “[a] notice of intent not to act and an accompanying declaratory order represent both [FERC’s] exercise of its discretion on such an enforcement action, as well as a statement of [FERC’s] position on the matters addressed.

⁵⁵⁶ 16 U.S.C. § 824a-3(h)(2)(B).

⁵⁵⁷ *FLS Energy, Inc., et al.*, 157 FERC ¶ 61,211, at P 19 (2016).

⁵⁵⁸ *Id.*

⁵⁵⁹ *Great Divide Wind Farm 2 and Great Divide Wind Farm 3*, 166 FERC ¶ 61,090, at P 20 (2019).

The statement of position by [FERC], in a case where, as here, [FERC] decides not to go to court on behalf of petitioners, can provide assistance to a court on [FERC’s] thinking in the event that the petitioners decide to bring enforcement cases.”⁵⁵⁸ However, FERC has explained that a Notice of Intent Not to Act without a declaratory order “cannot be read to mean that [FERC] has accepted or agreed with (or alternatively, rejected or disagreed with) any argument made by any party, or with any substantive determination by a state regulatory authority or unregulated electric utility.”⁵⁵⁹

One exception to this enforcement scheme is that section 210(h)(1) of PURPA gives FERC exclusive enforcement authority over any rules prescribed by FERC under section 210(a) of PURPA “with respect to any operations of an electric utility, a qualifying cogeneration



facility or a qualifying small power production facility which are subject to the jurisdiction of FERC under part II of the Federal Power Act.” As described in the 1983 Policy Statement, small power production facilities between 30 MW and 80 MW of capacity, other than geothermal facilities, cannot be exempt from the FPA, and thus the sales of electric power from these facilities would be “an ‘operation’ which is subject to [FERC’s] jurisdiction under Part II of the Federal Power Act.”⁵⁶⁰ Because

FERC has jurisdiction over these facilities, it has the authority to establish the rates for sale from these facilities, and “may require that the rate for purchase by an electric utility from such a [QF] be consistent with the [FERC]-established rate.”⁵⁶¹ However, FERC has determined that rates established by states that are otherwise consistent with FERC’s regulations will generally be accepted as just and reasonable under the FPA.⁵⁶²

560 1983 Policy Statement at 61,646.

561 *Id.*

562 *Id.*







PURPA
Section 210
16 U.S.C. § 824a-3 (2020)

PURPA Section 210, 16 U.S.C. § 824a-3 (2020)

§ 824a-3. Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to--

- (1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and
- (2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable

opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase--

- (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
- (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.





No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities

The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale--

- (1) shall be just and reasonable and in the public interest, and
- (2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric

energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions

- (1) Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act, from the Public Utility Holding Company Act, from State laws and regulations respecting the rates, or respecting the financial or

organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

- (2) No qualifying small power production facility (other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act) which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act and from State laws and regulations referred to in such paragraph (1).
- (3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—
 - (A) any State law or regulation in effect in a State pursuant to subsection (f),
 - (B) the provisions of section 210, 211, or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act, or
 - (C) any license or permit requirement under part I of the Federal Power Act, any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

- (1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.
- (2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement

- (1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner, and under the same requirements, as judicial review may be obtained under section 2633 of



this title in the case of a proceeding to which section 2633 of this title applies.

- (2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 2633 of this title with respect to an action to which section 2633 of this title applies.

(h) Commission enforcement

- (1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act, such rule shall be treated as a rule under the Federal Power Act. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.
- (2) (A) The Commission may enforce the requirements of subsection (f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than—

- (i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f)1 or
- (ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) Federal contracts

No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after November 9, 1978, may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) New dams and diversions

Except for a hydroelectric project located at a Government dam (as defined in section 3(10) of the Federal Power Act) at which non-Federal hydroelectric development is permissible, this section shall not apply to any hydroelectric project which impounds or diverts the water of a natural watercourse by means of

a new dam or diversion unless the project meets each of the following requirements:

- (1) No substantial adverse effects

At the time of issuance of the license or exemption for the project, the Commission finds that the project will not have substantial adverse effects on the environment, including recreation and water quality. Such finding shall be made by the Commission after taking into consideration terms and conditions imposed under either paragraph (3) of this subsection or section 10 of the Federal Power Act (whichever is appropriate as required by that Act or the Electric Consumers Protection Act of 1986) and compliance with other environmental requirements applicable to the project.
- (2) Protected rivers

At the time the application for a license or exemption for the project is accepted by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to environmental consultation), such project is not located on either of the following:

 - (A) Any segment of a natural watercourse which is included in (or designated for potential inclusion in) a State or national wild and scenic river system.
 - (B) Any segment of a natural watercourse which the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.
- (3) Fish and wildlife terms and conditions

The project meets the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act.

(k) "New dam or diversion" defined

For purposes of this section, the term "new dam or diversion" means a dam or diversion which requires, for purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards or similar adjustable devices).

(l) Definitions

For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act.

(m) Termination of mandatory purchase and sale requirements

- (1) Obligation to purchase

After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—

 - (A) (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or
 - (B) (i) transmission and interconnection services that are provided by a Commission-approved regional

transmission entity and administered pursuant to an open

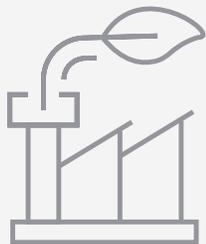
access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

- (C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

- (2) Revised purchase and sale obligation for new facilities

- (A) After August 8, 2005, no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n).
- (B) For the purposes of this paragraph, the term "existing qualifying cogeneration facility" means a facility that—
- (i) was a qualifying cogeneration facility on August 8, 2005; or
 - (ii) had filed with the Commission a notice of self-certification, self recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by subsection (n).





(3) Commission review

Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) have been met.

(4) Reinstatement of obligation to purchase

At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially

affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

(5) Obligation to sell

After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to sell electric energy to a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that—

- (A) competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and
- (B) the electric utility is not required by State law to sell electric energy in its service territory.

(6) No effect on existing rights and remedies

Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or nonregulated electric utility on August 8, 2005, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

(7) Recovery of costs

- (A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity

from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

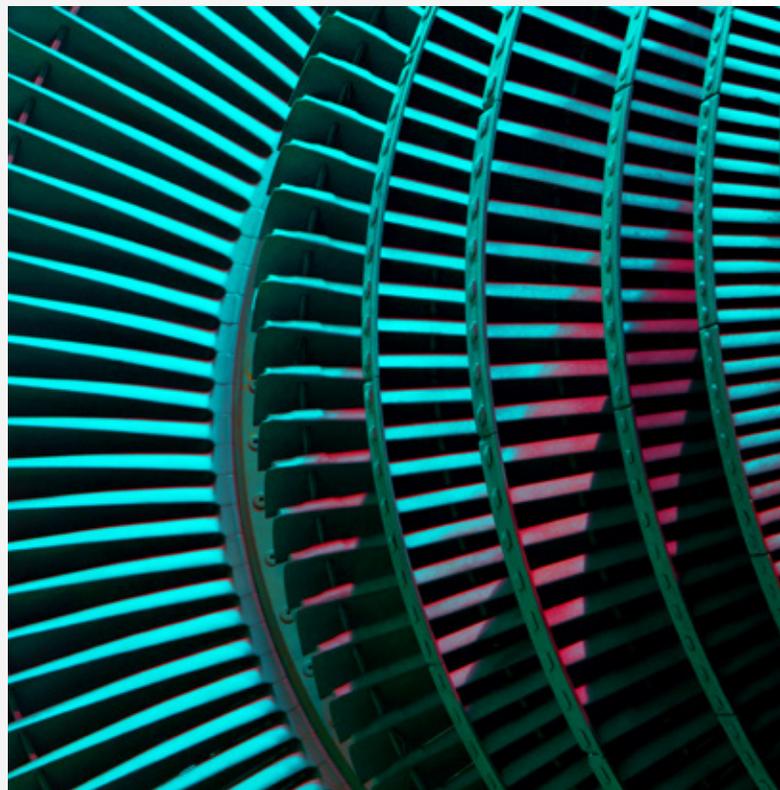
- (B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a et seq.).

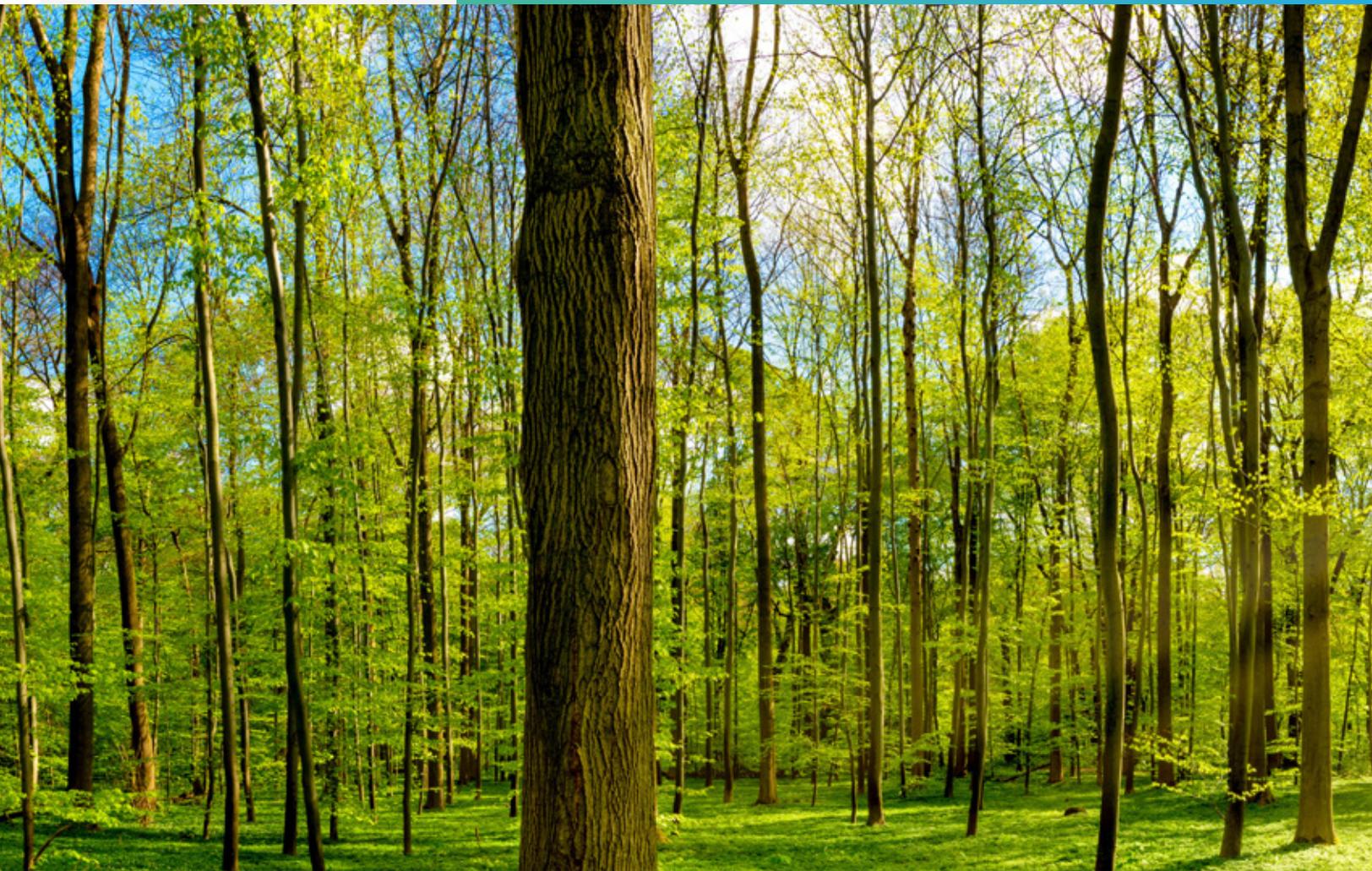
(n) Rulemaking for new qualifying facilities

- (1) (A) Not later than 180 days after August 8, 2005, the Commission shall issue a rule revising the criteria in 18 CFR 292.205 for new qualifying cogeneration facilities seeking to sell electric energy pursuant to this section to ensure—
- (i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;
 - (ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and
 - (iii) continuing progress in the development of efficient electric energy generating technology.
- (B) The rule issued pursuant to paragraph (1) (A) of this subsection shall be applicable only to facilities that seek to sell electric energy

pursuant to this section. For all other purposes, except as specifically provided in subsection (m)(2)(A), qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

- (2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that—
- (A) was a qualifying cogeneration facility on August 8, 2005, or
 - (B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).







PURPA Regulations

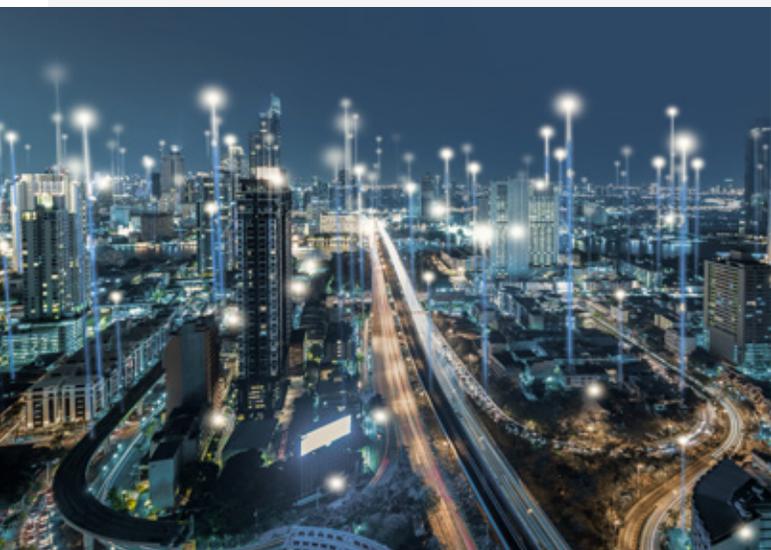
18 C.F.R.

Part 292 (2021)

18 C.F.R. Part 292 (2021)

§ 292.101 Definitions.

- (a) General rule. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.
- (b) Definitions. The following definitions apply for purposes of this part.
- (1) Qualifying facility means a cogeneration facility or a small power production facility that is a qualifying facility under Subpart B of this part.
 - (i) A qualifying facility may include transmission lines and other equipment used for interconnection purposes (including transformers and switchyard equipment), if:
 - (A) Such lines and equipment are used to supply power output to directly and indirectly interconnected electric utilities, and to end users, including thermal hosts, in accordance with state law; or
 - (B) Such lines and equipment are used to transmit supplementary, standby, maintenance and backup power to the qualifying facility, including its thermal host meeting the criteria set forth in *Union Carbide Corporation*, 48 FERC ¶ 61,130, reh'g denied, 49 FERC ¶ 61,209 (1989), aff'd sub nom., *Gulf States Utilities Company v. FERC*, 922 F.2d 873 (D.C. Cir. 1991); or
 - (C) If such lines and equipment are used to transmit power from other qualifying facilities or to transmit standby, maintenance, supplementary and backup power to other qualifying facilities.
 - (ii) The construction and ownership of such lines and equipment shall be subject to any applicable Federal, state, and local siting and environmental requirements.





- (2) Purchase means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.
- (3) Sale means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.
- (4) System emergency means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.
- (5) Rate means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.
- (6) Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.
- (7) Interconnection costs means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

- (8) Supplementary power means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.
- (9) Back-up power means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.
- (10) Interruptible power means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.
- (11) Maintenance power means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.
- (12) Locational marginal price means the price for energy at a particular location as determined in a market defined in § 292.309(e), (f), or (g).
- (13) Competitive Price means a Market Hub Price or a Combined Cycle Price.
- (14) Market Hub Price means a price for as-delivered energy determined pursuant to § 292.304(b)(7)(i).
- (15) Combined Cycle Price means a price for as-delivered energy determined pursuant to § 292.304(b)(7)(ii).
- (16) Competitive Solicitation Price means a price for energy and/or capacity determined pursuant to § 292.304(b)(8).

§ 292.201 Scope.

This subpart applies to the criteria for and manner of becoming a qualifying small power production facility and a qualifying cogeneration facility under sections

3(17)(C) and 3(18)(B), respectively, of the Federal Power Act, as amended by section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

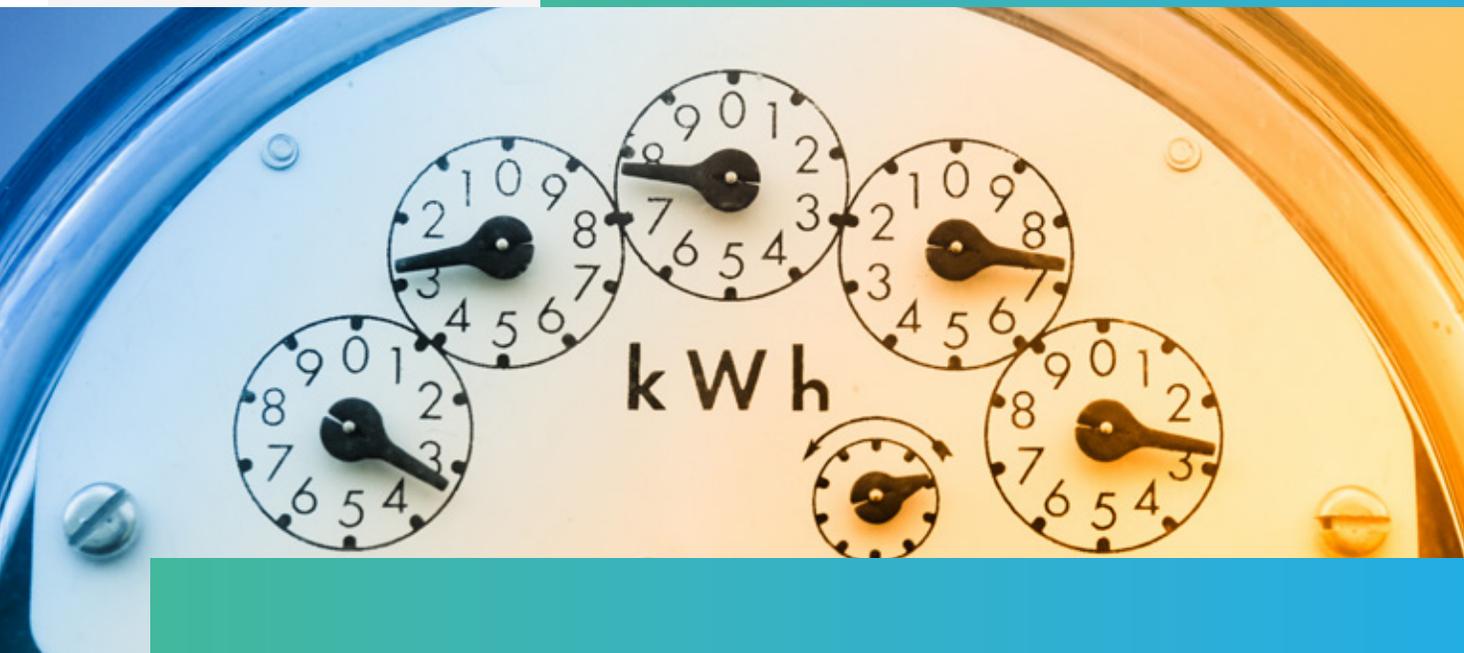
§ 292.202 Definitions.

For purposes of this subpart:

- (a) Biomass means any organic material not derived from fossil fuels;
- (b) Waste means an energy input that is listed below in this subsection, or any energy input that has little or no current commercial value and exists in the absence of the qualifying facility industry. Should a waste energy input acquire commercial value after a facility is qualified by way of Commission certification pursuant to § 292.207(b), or self-certification pursuant to § 292.207(a), the facility will not lose its qualifying status for that reason. Waste includes, but is not limited to, the following materials that the Commission previously has approved as waste:
 - (1) Anthracite culm produced prior to July 23, 1985;
 - (2) Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more;
 - (3) Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more;
 - (4) Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Management (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste.

- (5) Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the BLM or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste.
 - (6) Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation;
 - (7) Gaseous fuels, except:
 - (i) Synthetic gas from coal; and
 - (ii) Natural gas from gas and oil wells unless the natural gas meets the requirements of § 2.400 of this chapter;
 - (8) Petroleum coke;
 - (9) Materials that a government agency has certified for disposal by combustion;
 - (10) Residual heat;
 - (11) Heat from exothermic reactions;
 - (12) Used rubber tires;
 - (13) Plastic materials; and
 - (14) Refinery off-gas.
- (c) Cogeneration facility means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy;
 - (d) Topping-cycle cogeneration facility means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and at least some of the reject heat from the power production process is then used to provide useful thermal energy;
 - (e) Bottoming-cycle cogeneration facility means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for power production;
 - (f) Supplementary firing means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility;
 - (g) Useful power output of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process;
 - (h) Useful thermal energy output of a topping-cycle cogeneration facility means the thermal energy:
 - (1) That is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water);
 - (2) That is used in a heating application (e.g., space heating, domestic hot water heating);
 - (3) That is used in a space cooling application (i.e., thermal energy used by an absorption chiller); or





- (4) That is used by a fuel cell system with an integrated steam hydrocarbon reformation process for production of fuel for electricity generation.
- (i) Total energy output of a topping-cycle cogeneration facility is the sum of the useful power output and useful thermal energy output;
- (j) Total energy input means the total energy of all forms supplied from external sources;
- (k) Natural gas means either natural gas unmixed, or any mixture of natural gas and artificial gas;
- (l) Oil means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products; and
- (m) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of the natural gas or oil.
- (n) Electric utility holding company means a holding company, as defined in section 2(a)(7) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(7) which owns one or more electric utilities, as defined in section 2(a)(3) of that Act, 15 U.S.C. 79b(a)(3), but does not include any holding company which is exempt by rule or order adopted or issued pursuant to sections 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79c(a)(3) or 79c(a)(5).
- (o) Utility geothermal small power production facility means a small power production facility which uses geothermal energy as the primary energy resource and of which more than 50 percent is owned either:
- (1) By an electric utility or utilities, electric utility holding company or companies, or any combination thereof.
 - (2) By any company 50 percent or more of the outstanding voting securities of which are directly or indirectly owned, controlled, or held with power to vote by an electric utility, electric utility holding company, or any combination thereof.
- (p) New dam or diversion means a dam or diversion which requires, for the purposes of installing any hydroelectric power project,

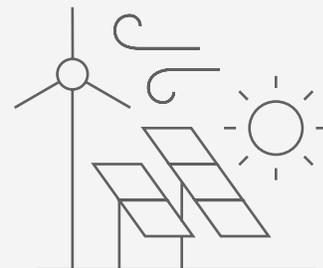
any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards of similar adjustable devices);

- (q) Substantial adverse effect on the environment means a substantial alteration in the existing or potential use of, or a loss of, natural features, existing habitat, recreational uses, water quality, or other environmental resources. Substantial alteration of particular resource includes a change in the environment that substantially reduces the quality of the affected resources; and
- (r) Commitment of substantial monetary resources means the expenditure of, or commitment to expend, at least 50 percent of the total cost of preparing an application for license or exemption for a hydroelectric project that is accepted for filing by the Commission pursuant to § 4.32(e) of this chapter. The total cost includes (but is not limited to) the cost of agency consultation, environmental studies, and engineering studies conducted pursuant to § 4.38 of this chapter, and the Commission's requirements for filing an application for license exemption.
- (s) Sequential use of energy means:
 - (1) For a topping-cycle cogeneration facility, the use of reject heat from a power production process in sufficient amounts in a thermal application or process to conform to the requirements of the operating standard; or
 - (2) For a bottoming-cycle cogeneration facility, the use of reject heat from a thermal application or process, at least some of which is then used for power production.
- (t) 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.

§ 292.203 General requirements for qualification.

- (a) Small power production facilities. Except as provided in paragraph (c) of this section, a small power production facility is a qualifying facility if it:
 - (1) Meets the maximum size criteria specified in § 292.204(a);
 - (2) Meets the fuel use criteria specified in § 292.204(b); and
 - (3) Unless exempted by paragraph (d), has filed with the Commission a notice of self-certification, pursuant to § 292.207(a); or has filed with the Commission an application for Commission certification, pursuant to § 292.207(b)(1), that has been granted.
- (b) Cogeneration facilities. A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a qualifying facility if it:
 - (1) Meets any applicable standards and criteria specified in §§ 292.205(a), (b) and (d); and



- (2) Unless exempted by paragraph (d), has filed with the Commission a notice of self-certification, pursuant to § 292.207(a); or has filed with the Commission an application for Commission certification, pursuant to § 292.207(b)(1), that has been granted.
- (c) Hydroelectric small power production facilities located at a new dam or diversion.
 - (1) A hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in § 292.202(p)) is a qualifying facility if it meets the requirements of:
 - (i) Paragraph (a) of this section; and
 - (ii) Section 292.208.
 - (2) [Reserved]
- (d) Exemptions and waivers from filing requirement.
 - (1) Any facility with a net power production capacity of 1 MW or less is exempt from the filing requirements of paragraphs (a) (3) and (b)(2) of this section.
 - (2) The Commission may waive the requirement of paragraphs (a)(3) and (b) (2) of this section for good cause. Any applicant seeking waiver of paragraphs (a)(3) and (b)(2) of this section must file a petition for declaratory order describing in detail the reasons waiver is being sought.

§ 292.204 Criteria for qualifying small power production facilities.

- (a) Size of the facility—
 - (1) Maximum size. Except as provided in paragraph (a)(4) of this section, the power production capacity of a facility for

which qualification is sought, together with the power production capacity of any other small power production qualifying facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.

- (2) Method of calculation.
 - (i) (A) For purposes of this paragraph (a) (2), there is an irrebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located one mile or less from the facility for which qualification or recertification is sought are located at the same site as the facility for which qualification or recertification is sought.
 - (B) For purposes of this paragraph (a) (2), for facilities for which qualification or recertification is filed on or after December 31, 2020 there is an irrebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located 10 miles or more



from the facility for which qualification or recertification is sought are located at separate sites from the facility for which qualification or recertification is sought.

(C) For purposes of this paragraph (a) (2), for facilities for which qualification or recertification is filed on or after December 31, 2020, there is a rebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located more than one mile and less than 10 miles from the facility for which qualification or recertification is sought are located at separate sites from the facility for which qualification or recertification is sought.

(D) For hydroelectric facilities, facilities are considered to be located at the same site as the facility for which qualification or recertification is sought if they are located within one mile of the facility for which qualification or recertification is sought and use water from the same impoundment for power generation.

- (ii) For purposes of making the determinations in paragraph (a)(2) (i), the distance between two facilities shall be measured from the edge of the closest electrical generating equipment for which qualification or recertification is sought to the edge of the nearest electrical generating equipment of the other affiliated small power production qualifying facility using the same energy resource.
- (3) Waiver. The Commission may modify the application of paragraph (a)(2) of this section, for good cause.
- (4) Exception. Facilities meeting the criteria in section 3(17)(E) of the Federal Power Act

(16 U.S.C. 796(17)(E)) have no maximum size, and the power production capacity of such facilities shall be excluded from consideration when determining the size of other small power production facilities less than 10 miles from such facilities.

(b) Fuel use.

- (1) (i) The primary energy source of the facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources.
 - (ii) Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.
- (2) Use of oil, natural gas and coal by a facility, under section 3(17)(B) of the Federal Power Act, is limited to the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and the minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages, and emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. Such fuel use may not, in the aggregate, exceed 25 percent of the total energy input of the facility during the 12-month period beginning with the date the facility first produces electric energy and any calendar year subsequent to the year in which the facility first produces electric energy.

§ 292.205 Criteria for qualifying cogeneration facilities.

- (a) Operating and efficiency standards for topping-cycle facilities—

- (1) Operating standard. For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must be no less than 5 percent of the total energy output during the 12-month period beginning with the date the facility first produces electric energy, and any calendar year subsequent to the year in which the facility first produces electric energy.
- (2) Efficiency standard.
 - (i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during the 12-month period beginning with the date the facility first produces electric energy, and any calendar year subsequent to the year in which the facility first produces electric energy, must:
 - (A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or
 - (B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.
 - (ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.
- (b) Efficiency standards for bottoming-cycle facilities.
 - (1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility during the 12-month period beginning with the date the facility first produces electric energy, and any calendar year subsequent to the year in which the facility first produces electric energy must be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.
 - (2) For any bottoming-cycle cogeneration facility not covered by paragraph (b) (1) of this section, there is no efficiency standard.
 - (c) Waiver. The Commission may waive any of the requirements of paragraphs (a) and (b) of this section upon a showing that the facility will produce significant energy savings.
 - (d) Criteria for new cogeneration facilities. Notwithstanding paragraphs (a) and (b) of this section, any cogeneration facility that was either not a qualifying cogeneration facility on or before August 8, 2005, or that had not filed a notice of self-certification or an application for Commission certification as a qualifying cogeneration facility under § 292.207 of this chapter prior to February 2, 2006, and which is seeking to sell electric energy pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 824a-1, must also show:
 - (1) The thermal energy output of the cogeneration facility is used in a productive and beneficial manner; and
 - (2) The electrical, thermal, chemical and mechanical output of the cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended

fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

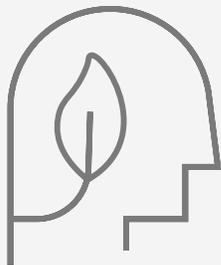
- (3) Fundamental use test. For the purpose of satisfying paragraph (d)(2) of this section, the electrical, thermal, chemical and mechanical output of the cogeneration facility will be considered used fundamentally for industrial, commercial, or institutional purposes and not intended fundamentally for sale to an electric utility if at least 50 percent of the aggregate of such output, on an annual basis, is used for industrial, commercial, residential or institutional purposes. In addition, applicants for facilities that do not meet this safe harbor standard may present evidence to the Commission that the facilities should nevertheless be certified given state laws applicable to sales of electric energy or unique technological, efficiency, economic, and variable thermal energy requirements.
- (4) For purposes of paragraphs (d)(1) and (2) of this section, a new cogeneration facility of 5 MW or smaller will be presumed to satisfy the requirements of those paragraphs.
- (5) For purposes of paragraph (d)(1) of this section, where a thermal host existed prior to the development of a new cogeneration facility whose thermal output will supplant the thermal source previously in use by the thermal host, the thermal output of such new cogeneration facility will be presumed to satisfy the requirements of paragraph (d)(1).

§ 292.206 [Reserved]

§ 292.207 Procedures for obtaining qualifying status.

- (a) Self-certification.
 - (1) FERC Form No. 556. The qualifying facility status of an existing or a proposed facility that meets the requirements of § 292.203 may be self-certified by the owner or operator of the facility or its representative by properly completing a FERC Form No. 556 and filing that form with the Commission, pursuant to § 131.80 of this chapter, and complying with paragraph (e) of this section.
 - (2) Factors. For small power production facilities pursuant to § 292.204, the owner or operator of the facility or its representative may, when completing the FERC Form No. 556, provide information asserting factors showing that the facility for which qualification or recertification is sought is at a separate site from other facilities using the same energy resource and owned by the same person(s) or its affiliates.





- (3) Commission action. Self-certification and self-recertification are effective upon filing. If no protests to a self-certification or self-recertification are timely filed pursuant to paragraph (c) of this section, no further action by the Commission is required for a self-certification or self-recertification to be effective. If protests to a self-certification or self-recertification are timely filed pursuant to paragraph (c) of this section, a self-certification or self-recertification will remain effective until the Commission issues an order revoking QF certification. The Commission will act on the protest within 90 days from the date the protest is filed; provided that, if the Commission requests more information from the protester, the entity seeking qualification or recertification, or both, the time for the Commission to act will be extended to 60 days from the filing of a complete answer to the information request. In addition to any extension resulting from a request for information, the Commission also may toll the 90-day period for one additional 60-day period if so required to rule on a protest. Authority to toll the 90-day period for this purpose is delegated to the Secretary or the Secretary's designee. Absent Commission action before the expiration of the tolling period, a protest will be deemed denied, and the self-certification or self-recertification will remain effective.

(b) Optional procedure—Commission certification.

- (1) Application for Commission certification. In lieu of the self-certification procedures in paragraph (a) of this section, an owner or operator of an existing or a proposed facility, or its representative, may file with the Commission an application for Commission certification that the facility is a qualifying facility. The application must be accompanied by the fee prescribed by part 381 of this chapter, and the applicant for Commission certification must comply with paragraph (c) of this section.
- (2) General contents of application. The application must include a properly completed FERC Form No. 556 pursuant to § 131.80 of this chapter. For small power production facilities pursuant to § 292.204, the owner or operator of the facility or its representative may, when completing the FERC Form No. 556, provide information asserting factors showing that the facility for which qualification is sought is at a separate site from other facilities using the same energy resource and owned by the same person(s) or its affiliates.
- (3) Commission action.
- (i) Within 90 days of the later of the filing of an application or the filing of a supplement, amendment or other change to the application, the Commission will either: Inform the applicant that the application is deficient; or issue an order granting or denying the application; or toll the time for issuance of an order. Any order denying certification shall identify the specific requirements which were not met. If the Commission does not act within 90 days of the date of the latest filing, the application shall be deemed to have been granted.



- (ii) For purposes of paragraph (b) of this section, the date an application is filed is the date by which the Office of the Secretary has received all of the information and the appropriate filing fee necessary to comply with the requirements of this Part.
- (c) Protests and Interventions.
 - (1) Filing a Protest. Any person, as defined in § 385.102(d) of this chapter, who opposes either a self-certification or self-recertification making substantive changes to the existing certification filed pursuant to paragraph (a) of this section or an application for Commission certification or Commission recertification making substantive changes to the existing certification filed pursuant to paragraph (b) of this section for which qualification or recertification is filed on or after December 31, 2020, may file a protest with the Commission. Any protest to and any intervention in a self-certification or self-recertification must be filed in accordance with §§ 385.211 and 385.214 of this chapter, on or before 30 days from the date the self-certification or self-recertification is filed. Any protestor must concurrently serve a copy of such filing pursuant to § 385.211 of this chapter. Any protest must be adequately supported, and provide any supporting documents, contracts, or affidavits to substantiate the claims in the protest.
 - (2) Limitations on protest. Protests may be filed to any initial self-certification or application for Commission certification filed on or after the effective date of this final rule, and to any self-recertification or application for Commission recertification that are filed on or after December 31, 2020 that makes substantive changes to the existing certification. Once the Commission has certified an applicant's qualifying facility status either in response to a protest opposing a self-certification or self-recertification, or in response to an

application for Commission certification or Commission recertification, any later protest to a self-recertification or application for Commission recertification making substantive changes to a qualifying facility's certification must demonstrate changed circumstances that call into question the continued validity of the certification.

- (d) Response to protests. Any response to a protest must be filed on or before 30 days from the date of filing of that protest and will be allowed under § 385.213(a)(2) of this chapter.
- (e) Notice requirements.
 - (1) General. An applicant filing a self-certification, self-recertification, application for Commission certification or application for Commission recertification of the qualifying status of its facility must concurrently serve a copy of such filing on each electric utility with which it expects to interconnect, transmit or sell electric energy to, or purchase supplementary, standby, back-up or maintenance power from, and the State regulatory authority

of each state where the facility and each affected electric utility is located. The Commission will publish a notice in the Federal Register for each application for Commission certification and for each self-certification of a cogeneration facility that is subject to the requirements of § 292.205(d).

- (2) Facilities of 500 kW or more. An electric utility is not required to purchase electric energy from a facility with a net power production capacity of 500 kW or more until 90 days after the facility notifies the facility that it is a qualifying facility or 90 days after the utility meets the notice requirements in paragraph (c)(1) of this section.
- (f) Revocation of qualifying status.
 - (1) (i) If a qualifying facility fails to conform with any material facts or representations presented by the cogenerator or small power producer in its submittals to the Commission, the notice of self-certification or Commission order certifying the qualifying status of the facility may no longer be relied upon. At that point, if the facility continues to conform to the Commission's qualifying criteria under this part, the cogenerator or small power producer may file either a notice of self-recertification of qualifying status pursuant to the requirements of paragraph (a) of this section, or an application for Commission recertification pursuant to the requirements of paragraph (b) of this section, as appropriate.
 - (ii) The Commission may, on its own motion or on the motion of any person, revoke the qualifying status of a facility that has been certified under paragraph



(b) of this section, if the facility fails to conform to any of the Commission's qualifying facility criteria under this part.

(iii) The Commission may, on its own motion or on the motion of any person, revoke the qualifying status of a self-certified or self-recertified qualifying facility if it finds that the self-certified or self-recertified qualifying facility does not meet the applicable requirements for qualifying facilities.

- (2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under paragraph (b) of this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status. This application for Commission recertification of qualifying status should be submitted in accordance with paragraph (b) of this section.

§ 292.208 Special requirements for hydroelectric small power production facilities located at a new dam or diversion.

- (a) A hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in § 292.202(p)) is a qualifying facility only if it meets the requirements of:
- (1) Paragraph (b) of this section;
 - (2) Section 292.203(c); and
 - (3) Part 4 of this chapter.
- (b) A hydroelectric small power production described in paragraph (a) is a qualifying facility only if:

- (1) The Commission finds, at the time it issues the license or exemption, that the project will not have a substantial adverse effect on the environment (as that term is defined in § 292.202(q)), including recreation and water quality;
 - (2) The Commission finds, at the time the application for the license or exemption is accepted for filing under § 4.32 of this chapter, that the project is not located on any segment of a natural watercourse which:
 - (i) Is included, or designated for potential inclusion in, a State or National wild and scenic river system; or
 - (ii) The State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural or scenic attributes which would be adversely affected by hydroelectric development; and
 - (3) The project meets the terms and conditions set by the appropriate fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act.
- (c) For the Commission to make the findings in paragraph (b) of this section an applicant must:
- (1) Comply with the applicable hydroelectric licensing requirements in Part 4 of this chapter, including:
 - (i) Completing the pre-filing consultation process under § 4.38 of this chapter, including performing any environmental studies which may be required under §§ 4.38(b)(2)(i)(D) through (F) of this chapter; and
 - (ii) Submitting with its application an environmental report that meets the



requirements of § 4.41(f) of this chapter, regardless of project size;

- (2) State whether the project is located on any segment of a natural watercourse which:
 - (i) Is included in or designated for potential inclusion in:
 - (A) The National Wild and Scenic River System (28 U.S.C. 1271–1278 (1982)); or
 - (B) A State wild and scenic river system;
 - (ii) Crosses an area designated or recommended for designation under the Wilderness Act (16 U.S.C. 1132) as:
 - (A) A wilderness area; or
 - (B) Wilderness study area; or
 - (iii) The State, either by or pursuant to an act of the State legislature, has determined to possess unique, natural, recreational, cultural, or scenic attributes that would be adversely affected by hydroelectric development.
- (d) If the project is located on any segment of a natural watercourse that meets any of the conditions in paragraph (c)(2) of this section, the applicant must provide the following information in its application:
 - (1) The date on which the natural watercourse was protected;
 - (2) The statutory authority under which the natural watercourse was protected; and
 - (3) The Federal or state agency, or political subdivision of the state, that is in charge of administering the natural watercourse.

§ 292.209 Exceptions from requirements for hydroelectric small power production facilities located at a new dam or diversion.

- (a) The requirements in §§ 292.208(b)(1) through (3) do not apply if:
 - (1) An application for license or exemption is filed for a project located at a Government dam, as defined in section 3(10) of the Federal Power Act, at which non-Federal hydroelectric development is permissible; or
 - (2) An application for license or exemption was filed and accepted before October 16, 1986.
- (b) The requirements in §§ 292.208(b) (1) and (3) do not apply if an application for license or exemption was filed before October 16, 1986, and is accepted for filing by the Commission before October 16, 1989.
- (c) The requirements in § 292.208(b)(3) do not apply to an applicant for license or exemption if:
 - (1) The applicant files a petition pursuant to § 292.210; and
 - (2) The Commission grants the petition.
- (d) Any application covered by paragraph (a), (b), or (c) of this section is excepted from the moratorium imposed by section 8(e) of the Electric Consumers Protection Act of 1986, Pub.L. No. 99–495.

§ 292.210 Petition alleging commitment of substantial monetary resources before October 16, 1986.

- (a) An applicant covered by § 292.203(c) whose application for license or exemption was filed on or after October 16, 1986, but before April 16, 1988, may file a petition for exception from the requirement in § 292.208(b)(3) and the moratorium described in § 292.203(c)(2). The petition must show that prior to October 16, 1986, the applicant committed substantial monetary resources (as that term is defined in § 292.202(r)) to the development of the project.
- (b) Subject to rebuttal under paragraph (d)(7)(ii) of this section, a showing of the commitment of substantial monetary resources will be presumed if the applicant held a preliminary permit for the project and had completed environmental consultations pursuant to § 4.38 of this chapter before October 16, 1986.
- (c) Time of filing petition—
 - (1) General rule. Except as provided in paragraph (c)(2) of this section, the applicant must:
 - (i) File the petition with the application for license or exemption; or
 - (ii) Submit with the application for license or exemption a request for an extension of time, not to exceed 90 days or April 16, 1988, whichever occurs first, in which to file the petition.
 - (2) Exception. If the application for license or exemption was filed on or after October 16, 1986, but before March 23, 1987, the petition must have been filed by June 22, 1987.
- (d) Filing requirements. A petition filed under this section must include the following information or refer to the pages in the application for license or exemption where it can be found:
 - (1) A certificate of service, conforming to the requirements set out in § 385.2010(h) of this chapter, certifying that the applicant has served the petition on the Federal and State agencies required to be consulted by the applicant pursuant to § 4.38 of this chapter;





- (2) Documentation of any issued preliminary permits for the project;
- (3) An itemized statement of the total costs expended on the application;
- (4) An itemized schedule of costs the applicant expended, or committed to be expended, before October 16, 1986, on the application, accompanied by supporting documentation including but not limited to:
 - (i) Dated invoices for maps, surveys, supplies, geophysical and geotechnical services, engineering services, legal services, document reproduction, and other items related to the preparation of the application, and
 - (ii) Written contracts and other written documentation demonstrating a commitment made before October 16, 1986, to expend monetary resources on the preparation of the application, together with evidence that those monetary resources were actually expended; and
- (5) Correspondence or other documentation to support the items listed in paragraphs (d)(3) and (d)(4) of this section to show that the expenses presented were directly related to the preparation of the application.
- (6) The applicant must include in its total cost statement and in its schedule of the costs expended or committed to be expended before October 16, 1986, the value of services that were performed by the applicant itself instead of contracted out.
- (7)
 - (i) If the applicant held a preliminary permit for the project and had completed pre-filing consultation pursuant to § 4.38 of this chapter prior to October 16, 1986, the applicant may, instead of submitting the information listed in paragraphs (d) (3), (d)(4), and (d)(5) of this section, submit a statement identifying the preliminary permit by project number.
 - (ii) If any interested person objects (pursuant to § 385.211 of this chapter) to

the presumption in paragraph (b) of this section, the applicant must supply the information listed in paragraphs (d)(3), (d)(4), and (d)(5) of this section.

- (8) If the application is deficient pursuant to § 4.32(e) of this chapter, the applicant must include with the information correcting those deficiencies a statement of the costs expended to make the corrections.
- (e) Processing of petition.
- (1) The Commission will issue a notice of the petition filed under this section and publish the notice in the Federal Register. The petition will be available for inspection and copying during regular business hours in the Public Reference Room maintained by the Division of Public Information.
 - (2) Comments on the petition. The Commission will provide the public 45 days from the date the notice of the petition is issued to submit comments. The applicant for license or exemption has 15 days after the expiration of the public comment period to respond to the comments filed with the Commission.
 - (3) Commission action on petition. The Director of the Office of Energy Projects will determine whether or not the applicant for license or exemption has made the showing required under this section.
- § 292.211 Petition for initial determination on whether a project has a substantial adverse effect on the environment (AEE petition).**
- (a) An applicant that has filed a petition under § 292.210 may also file an AEE petition with the Commission for an initial determination on whether the project satisfies the requirement that it has no substantial adverse effect on the environment as specified in § 292.208(b)(1).
 - (b) The filing of the AEE petition does not relieve the applicant of the filing requirements of § 292.208(c).
 - (c) The Commission will act on the AEE petition only if the Commission has granted the applicant's commitment of resources petition under § 292.210.
 - (d) Time of filing petition. The applicant may file the AEE petition with the application for license or exemption or at any time before the Commission issues the license or exemption.
 - (e) Contents of petition. The AEE petition must identify the project and request that the Commission make an initial determination on the adverse environmental effects requirements in § 292.208(b)(1).
 - (f) The Director of the Office of Energy Projects will make the initial determination on the AEE petition. In making this determination, the Director will consider the following:
 - (1) Any proposed mitigative measures;
 - (2) The consistency of the proposal with local, regional, and national resource plans and programs;
 - (3) The mandatory terms and conditions of fish and wildlife agencies under section 210(j) of PURPA, or section 30(c) of the Federal Power Act; or the recommended terms and conditions of fish and wildlife agencies under Section 10(j) of the Federal Power Act, whichever is appropriate; and
 - (4) Any other information which the Director believes is relevant to consider.
 - (g) Initial finding on the petition. The Director of the Office of Energy Projects will make the initial determination on the AEE petition after the close of the public notice period for the

accepted application. If the Director's initial determination finds:

- (1) No substantial adverse effect on the environment, the Commission must wait at least 45 days before making a final determination that the project satisfies the requirements of § 292.208(b)(1).
 - (2) A substantial adverse effect on the environment, the applicant may file, within 90 days of the initial finding that the project does not satisfy the requirements in § 292.208(b)(1), proposed measures to mitigate the adverse environmental effects found.
 - (3)
 - (i) The Commission will provide written notice of the Director's initial finding on the petition to the applicant, to the federal and state agencies that the applicant must consult under § 4.38 of this chapter and to any intervenors in the proceeding.
 - (ii) The Commission will publish notice of the Director's initial finding in the Federal Register.
- (h) Notice and comment on the mitigative measures.
- (1) The Commission will issue notice of the mitigative measures filed by an applicant under paragraph (g)(2) of this section and will publish the notice in the Federal Register. The mitigative measures will be on file and available for inspection or copying during regular business hours in the Public Reference Room maintained by the Division of Public Information;
 - (2) The Commission will provide the State and interested persons within 90 days from the date the notice is issued to review and submit comments on the mitigative measures. The applicant for license or exemption has 15 days after the expiration of the public comment period to respond to the comments filed with the Commission.
- (i) Material amendments to application. The proposed mitigative measures filed under paragraph (g)(2) of this section will not be considered a material amendment to the application unless the Commission finds that the proposed measures are unnecessary to, or exceed the scope of, mitigating substantial adverse effects. If the Commission finds the proposed mitigative measures constitute a material amendment, the application will be considered filed with the Commission on the date on which the applicant filed the proposed mitigative measures, and all other provisions of § 4.35(a) of this chapter will apply.
 - (j) Final determination on the petition. The Commission will make a final determination on the petition at the time the Commission issues a license or exemption for the project.
 - (k) Presumption.
 - (1) If, between the Commission's initial and final findings on the AEE petition, the State does not take any action under § 292.208(b)(2), the failure to take action can be the basis for a presumption that there is not substantial adverse effect on the environment (as that term is defined in § 292.202(q)).
 - (2) If the presumption in paragraph (k)(1) of this section comes into effect, it:
 - (i) Is only available for those adverse effects related to the natural, recreational, cultural, or scenic attributes of the environment;
 - (ii) Can only operate during the time between the Commission's initial and final findings on the AEE petition; and
 - (iii) Has no effect on the Commission's

independent obligation to find that the project will not have a substantial adverse effect on the environment under § 292.208(b)(1).

- (3) The presumption in paragraph (k)(1) of this section does not take effect if the State, the Commission or an interested person demonstrates that the State has acted to protect the natural watercourse under § 292.208(b)(2).
- (4) The presumption in paragraph (k)(1) of this section can be rebutted if:
 - (i) The Commission determines that the project will have a substantial adverse effect on the environment related to the environmental attributes listed in paragraph (k)(2)(i) of this section; or
 - (ii) Any interested person, including a State, demonstrates that the project will have a substantial adverse effect on the environment related to the environmental attributes listed in paragraph (k)(2)(i) of this section.

§ 292.301 Scope.

- (a) Applicability. This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.
- (b) Negotiated rates or terms. Nothing in this subpart:
 - (1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or
 - (2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

§ 292.302 Availability of electric utility system cost data.

- (a) Applicability.
 - (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.
 - (2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until June 30, 1982.



- (b) General rule. To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:
- (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
 - (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
 - (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.
- (c) Special rule for small electric utilities.
- (1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:
 - (i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or
 - (ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.





- (2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.
- (d) Substitution of alternative method.
 - (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any nonregulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.
 - (2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.
- (e) State Review.
 - (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.
 - (2) In any such review, the electric utility has the burden of coming forward with justification for its data.

§ 292.303 Electric utility obligations under this subpart.

- (a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase, in accordance with § 292.304, unless exempted by § 292.309 and § 292.310, any energy

and capacity which is made available from a qualifying facility:

- (1) Directly to the electric utility; or
- (2) Indirectly to the electric utility in accordance with paragraph (d) of this section.
- (b) Obligation to sell to qualifying facilities. Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, unless exempted by § 292.312, energy and capacity requested by the qualifying facility.
- (c) Obligation to interconnect.
 - (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnection with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.
 - (2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under part II of the Federal Power Act.
- (d) Transmission to other electric utilities. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such

energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

- (e) Parallel operation. Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

§ 292.304 Rates for purchases.

- (a) Rates for purchases.
- (1) Rates for purchases shall:
 - (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
 - (ii) Not discriminate against qualifying cogeneration and small power production facilities.
 - (2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.
- (b) Relationship to avoided costs.
- (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.
 - (2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.
 - (3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.
 - (4) Rates for purchases from new capacity shall be in accordance with paragraph (b) (2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.
 - (5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.
 - (6) Locational Marginal Price. There is a rebuttable presumption that a state regulatory authority or nonregulated electric utility may use a Locational Marginal Price as a rate for as-available qualifying facility energy sales to electric utilities located in a market defined in § 292.309(e), (f), or (g).
 - (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 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, determined as follows:



- (i) A Market Hub Price is a price established at a liquid market hub which a state regulatory authority or nonregulated electric utility determines represents an appropriate measure of the electric utility's avoided cost for as-available energy, and is a hub to which the electric utility has reasonable access, based on an evaluation by the state regulatory authority or nonregulated electric utility of the relevant factors, including but not limited to the following:
 - (A) Whether the hub is sufficiently liquid that prices at the hub represent a competitive price;
 - (B) Whether prices developed at the hub are sufficiently transparent;
 - (C) Whether the electric utility has the ability to deliver power from such hub to its load, even if its load is not directly connected to the hub; and
 - (D) Whether the hub represents an appropriate market to derive an energy price for the electric utility's purchases from the relevant qualifying facility given the electric utility's physical proximity to the hub or other factors.
- (ii) A Combined Cycle Price is a price determined pursuant to a formula established by a state regulatory authority or nonregulated electric utility using published natural gas price indices, a proxy heat rate, and variable operations and maintenance costs for an efficient natural gas combined-cycle generating facility. Before establishing such a formula rate, a state regulatory authority or nonregulated electric utility must determine that the resulting Combined Cycle Price represents an appropriate measure of the purchasing electric utility's avoided cost for energy, based on its evaluation of the relevant factors, including but not limited to the following:

- (A) Whether the cost of energy from an efficient natural gas combined cycle generating facility represents a reasonable measure of a competitive price in the purchasing electric utility's region;
 - (B) Whether natural gas priced pursuant to particular proposed natural gas price indices would be available in the relevant market;
 - (C) Whether there should be an adjustment to the natural gas price to appropriately reflect the cost of transporting natural gas to the relevant market; and
 - (D) Whether the proxy heat rate used in the formula should be updated regularly to reflect improvements in generation technology.
- (8) Competitive Solicitation Price.
- (i) A state regulatory authority or nonregulated electric utility may use a price determined pursuant to a competitive solicitation process to establish qualifying facility energy and/or capacity rates for sales to electric

utilities, provided that such competitive solicitation process is conducted pursuant to procedures ensuring the solicitation is conducted in a transparent and non-discriminatory manner including, but not limited to, the following:

- (A) The solicitation process is an open and transparent process that includes, but is not limited to, providing equally to all potential bidders substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality safeguards;
 - (B) Solicitations are open to all sources, to satisfy that electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity;
 - (C) Solicitations are conducted at regular intervals;
 - (D) Solicitations are subject to oversight by an independent administrator; and
 - (E) Solicitations are certified as fulfilling the above criteria by the relevant state regulatory authority or nonregulated electric utility through a post-solicitation report.
- (ii) To the extent that the electric utility procures all of its capacity, including capacity resources constructed or otherwise acquired by the electric utility, through a competitive solicitation process conducted pursuant to paragraph (b)(8)(i) of this section, the electric utility shall be presumed to have no avoided capacity costs unless and until it determines



to acquire capacity outside of such competitive solicitation process. However, the electric utility shall nevertheless be required to purchase energy from qualifying small power producers and qualifying cogeneration facilities.

- (iii) To the extent that the electric utility does not procure all of its capacity through a competitive solicitation process conducted pursuant to paragraph (b)(8)(i) of this section, then there shall be no presumption that the electric utility has no avoided capacity costs.

(c) Standard rates for purchases.

- (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.
- (2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.
- (3) The standard rates for purchases under this paragraph:
 - (i) Shall be consistent with paragraphs (a) and (e) of this section; and
 - (ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) Purchases "as available" or pursuant to a legally enforceable obligation.

- (1) Each qualifying facility shall have the option either:
 - (i) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based

on the electric utility's avoided cost for energy calculated at the time of delivery; or

- (ii) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, except as provided in paragraph (d)(2) of this section, be based on either:
 - (A) The avoided costs calculated at the time of delivery; or
 - (B) The avoided costs calculated at the time the obligation is incurred.
- (iii) The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery.
- (2) Notwithstanding paragraph (d)(1)(ii)(B) of this section, a state regulatory authority or nonregulated electric utility may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery.



- (3) Obtaining a legally enforceable obligation. A qualifying facility must demonstrate commercial viability and financial commitment to construct its facility pursuant to criteria determined by the state regulatory authority or nonregulated electric utility as a prerequisite to a qualifying facility obtaining a legally enforceable obligation. Such criteria must be objective and reasonable.
- (e) Factors affecting rates for purchases.
- (1) A state regulatory authority or nonregulated electric utility may establish rates for purchases of energy from a qualifying facility based on a purchasing electric utility's locational marginal price calculated by the applicable market defined in § 292.309(e), (f), or (g), or the purchasing electric utility's applicable Competitive Price. Alternatively, a state regulatory authority or nonregulated electric utility may establish rates for purchases of energy and/or capacity from a qualifying facility based on a Competitive Solicitation Price. To the extent that capacity rates are not set pursuant to this section, capacity rates shall be set pursuant to subsection (2).
- (2) To the extent that a state regulatory authority or nonregulated electric utility does not set energy and/or capacity rates pursuant to paragraph (e)(1) of this section, the following factors shall, to the extent practicable, be taken into account in determining rates for purchases from a qualifying facility:
- (i) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
- (ii) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
- (A) The ability of the electric utility to dispatch the qualifying facility;
- (B) The expected or demonstrated reliability of the qualifying facility;
- (C) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
- (D) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the electric utility's facilities;
- (E) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
- (F) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
- (G) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
- (iii) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) (ii) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
- (iv) The costs or savings resulting from variations in line losses from those that

would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

- (f) Periods during which purchases not required.
- (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.
 - (2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.
 - (3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f) (1) of this section not occurred.
 - (4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

- (a) General rules.
 - (1) Rates for sales:
 - (i) Shall be just and reasonable and in the public interest; and
 - (ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.
 - (2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.
- (b) Additional services to be provided to qualifying facilities.
 - (1) Upon request of a qualifying facility, each electric utility shall provide:
 - (i) Supplementary power;
 - (ii) Back-up power;
 - (iii) Maintenance power; and
 - (iv) Interruptible power.





(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

- (i) Impair the electric utility's ability to render adequate service to its customers; or
- (ii) Place an undue burden on the electric utility.

(c) Rates for sales of back-up and maintenance power. The rate for sales of back-up power or maintenance power:

(1) Shall not be based upon an assumption

(unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

§ 292.306 Interconnection costs.

(a) Obligation to pay. Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

- (b) Reimbursement of interconnection costs. Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 System emergencies.

- (a) Qualifying facility obligation to provide power during system emergencies. A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:
- (1) Provided by agreement between such qualifying facility and electric utility; or
 - (2) Ordered under section 202(c) of the Federal Power Act.
- (b) Discontinuance of purchases and sales during system emergencies. During any system emergency, an electric utility may discontinue:
- (1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and
 - (2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

§ 292.309 Termination of obligation to purchase from qualifying facilities.

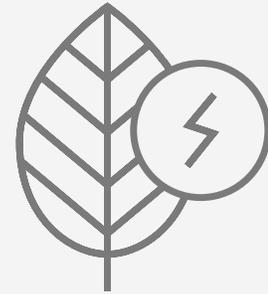
- (a) After August 8, 2005, an electric utility shall not be required, under this part, to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility if the Commission finds that the qualifying cogeneration facility or qualifying small power facility production has nondiscriminatory access to:
- (1) (i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) Wholesale markets for long-term sales of capacity and electric energy; or
 - (2) (i) Transmission and interconnection services that are provided by a Commission-approved regional 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, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or
 - (3) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in paragraphs (a)(1) and (a)(2) of this section.

- (b) For purposes of § 292.309(a), a renewal of a contract that expires by its own terms is a “new contract or obligation” without a continuing obligation to purchase under an expired contract.
- (c) For purposes of paragraphs (a)(1), (2) and (3) of this section, with the exception of paragraph (d) of this section, there is a rebuttable presumption that a qualifying facility has nondiscriminatory access to the market if it is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, and Commission-approved interconnection rules.
- (1) If the Commission determines that a market meets the criteria of paragraphs (a)(1), (2) or (3) of this section, and if a qualifying facility in the relevant market is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, a qualifying facility may seek to rebut the presumption of access to the market by demonstrating, inter alia, that it does not have access to the market because of operational characteristics or transmission constraints.
- (2) For purposes of paragraphs (a)(1), (2), and (3) of this section, a qualifying small power production facility with a capacity between 5 megawatts and 20 megawatts may additionally seek to rebut the presumption of access to the market by demonstrating that it does not have access to the market in light of consideration of other factors, including, but not limited to:
- (i) Specific barriers to connecting to the interstate transmission grid, such as excessively high costs and pancaked delivery rates;
 - (ii) Unique circumstances impacting the time or length of interconnection studies or queues to process the small power production facility’s interconnection request;
 - (iii) A lack of affiliation with entities that participate in the markets in paragraphs (a)(1), (2), and (3) of this section;
 - (iv) The qualifying small power production facility has a predominant purpose other than selling electricity and should be treated similarly to qualifying cogeneration facilities;
 - (v) The qualifying small power production facility has certain operational characteristics that effectively prevent the qualifying facility’s participation in a market; or
 - (vi) The qualifying small power production facility lacks access to markets due to transmission constraints. The qualifying small power production facility may show that it is located in an area where persistent transmission constraints in



effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.

- (d) (1) For purposes of paragraphs (a)(1), (2), and (3) of this section, there is a rebuttable presumption that a qualifying cogeneration facility with a capacity at or below 20 megawatts does not have nondiscriminatory access to the market.
- (2) For purposes of paragraphs (a)(1), (2), and (3) of this section, there is a rebuttable presumption that a qualifying small power production facility with a capacity at or below 5 megawatts does not have nondiscriminatory access to the market.
- (3) Nothing in paragraphs (d)(1) through (3) affects the rights the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or nonregulated electric utility on or before February 16, 2021, to purchase electric energy or capacity from or to sell electric energy or capacity to a small power production facility between 5 megawatts and 20 megawatts under this Act (including the right to recover costs of purchasing electric energy or capacity).
- (4) For purposes of implementing paragraphs (d)(1) and (2) of this section, the Commission will not be bound by the standards set forth in § 292.204(a)(2).
- (e) Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), ISO New England Inc. (ISO-NE), and New York Independent System Operator, Inc. (NYISO) qualify as markets described in paragraphs (a)(1)(i) and (ii) of this section, and there is a rebuttable presumption that small power production facilities with a capacity greater than 5 megawatts and cogeneration facilities



with a capacity greater than 20 megawatts have nondiscriminatory access to those markets through Commission-approved open access transmission tariffs and interconnection rules, and that electric utilities that are members of such regional transmission organizations or independent system operators should be relieved of the obligation to purchase electric energy from the qualifying facilities.

- (1) A qualifying facility above 20 MW may seek to rebut this presumption by demonstrating, inter alia, that:
- (i) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or
 - (ii) The qualifying facility lacks access to markets due to transmission constraints. The qualifying facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.
- (2) A small power producer qualifying facility between 5 megawatts and 20 megawatts may show it does not have access to the market in light of consideration of other factors, including, but not limited to:
- (i) Specific barriers to connecting to the interstate transmission grid, such as

- excessively high costs and pancaked delivery rates;
- (ii) Unique circumstances impacting the time or length of interconnection studies or queues to process the small power production facility's interconnection request;
 - (iii) A lack of affiliation with entities that participate in the markets in section § 292.309(a)(1), (2), and (3);
 - (iv) The qualifying small power production facility has a predominant purpose other than selling electricity and should be treated similarly to qualifying cogeneration facilities;
 - (v) The qualifying small power production facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or
 - (vi) The qualifying small power production facility lacks access to markets due to transmission constraints. The qualifying small power production facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.
- (f) The Electric Reliability Council of Texas (ERCOT) qualifies as a market described in paragraph (a)(3) of this section, and there is a rebuttable presumption that small power production facilities with a capacity greater than five megawatts and cogeneration facilities with a capacity greater than 20 megawatts have nondiscriminatory access to that market through Public Utility Commission of Texas (PUCT) approved open access protocols, and that electric utilities that operate within ERCOT should be relieved of the obligation to purchase electric energy from the qualifying facilities.
- (1) A qualifying facility above 20 MW may seek to rebut this presumption by demonstrating, inter alia, that:
 - (i) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or
 - (ii) The qualifying facility lacks access to markets due to transmission constraints. The qualifying facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.
 - (2) A small power producer qualifying facility between 5 megawatts and 20 megawatts may show it does not have access to the market in light of consideration of other factors, including, but not limited to:
 - (i) Specific barriers to connecting to the interstate transmission grid, such as excessively high costs and pancaked delivery rates;
 - (ii) Unique circumstances impacting the time or length of interconnection studies or queues to process the small power production facility's interconnection request;
 - (iii) A lack of affiliation with entities that participate in the markets in section § 292.309(a)(1), (2), and (3);
 - (iv) The qualifying small power production facility has a predominant purpose other than selling electricity and

should be treated similarly to qualifying cogeneration facilities;

- (v) The qualifying small power production facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or
- (vi) The qualifying small power production facility lacks access to markets due to transmission constraints. The qualifying small power production facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.
- (g) The California Independent System Operator and Southwest Power Pool, Inc. satisfy the criteria of § 292.309(a)(2)(i).
- (h) No electric utility shall be required, under this part, to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for new qualifying cogeneration facilities established by the Commission in § 292.205.
 - (i) For purposes of § 292.309(h), an "existing qualifying cogeneration facility" is a facility that:
 - (1) Was a qualifying cogeneration facility on or before August 8, 2005; or
 - (2) Had filed with the Commission a notice of self-certification or self-recertification, or an application for Commission certification, under § 292.207 prior to February 2, 2006.
 - (j) For purposes of § 292.309(h), a "new qualifying cogeneration facility" is a facility that satisfies the criteria for qualifying cogeneration facilities pursuant to § 292.205.

§ 292.310 Procedures for utilities requesting termination of obligation to purchase from qualifying facilities.

- (a) An electric utility may file an application with the Commission for relief from the mandatory purchase requirement under § 292.303(a) pursuant to this section on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in § 292.309(a)(1), (2) or (3) have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and



an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in § 292.309(a)(1), (2) or (3) have been met.

- (b) Sufficient notice shall mean that an electric utility must identify with names and addresses all potentially affected qualifying facilities in an application filed pursuant to paragraph (a).
- (c) An electric utility must submit with its application for each potentially affected qualifying facility: The docket number assigned if the qualifying facility filed for self-certification or an application for Commission certification of qualifying facility status; the net capacity of the qualifying facility; the location of the qualifying facility depicted by state and county, and the name and location of the substation where the qualifying facility is interconnected; the interconnection status of each potentially affected qualifying facility including whether the qualifying facility is interconnected as an energy or a network resource; and the expiration date of the energy and/or capacity agreement between the applicant utility and each potentially affected qualifying facility. All potentially affected qualifying facilities shall include:
 - (1) Those qualifying facilities that have existing power purchase contracts with the applicant;
 - (2) Other qualifying facilities that sell their output to the applicant or that have pending self-certification or Commission certification with the Commission for qualifying facility status whereby the applicant will be the purchaser of the qualifying facility's output;
 - (3) Any developer of generating facilities with whom the applicant has agreed to enter into power purchase contracts, as of the date of the application filed pursuant to

this section, or are in discussion, as of the date of the application filed pursuant to this section, with regard to power purchase contracts;

- (4) The developers of facilities that have pending state avoided cost proceedings, as of the date of the application filed pursuant to this section; and
 - (5) Any other qualifying facilities that the applicant reasonably believes to be affected by its application filed pursuant to paragraph (a) of this section.
- (d) The following information must be filed with an application:
- (1) Identify whether applicant seeks a finding under the provisions of § 292.309(a)(1), (2), or (3).
 - (2) A narrative setting forth the factual basis upon which relief is requested and describing why the conditions set forth in § 292.309(a)(1), (2), or (3) have been met. Applicant should also state in its application whether it is relying on the findings or rebuttable presumptions contained in § 292.309(e), (f) or (g). To the extent applicant seeks relief from the purchase obligation with respect to a qualifying facility 20 megawatts or smaller, and thus seeks to rebut the presumption in § 292.309(d), applicant must also set forth, and submit evidence of, the factual basis supporting its contention that the qualifying facility has nondiscriminatory access to the wholesale markets which are the basis for the applicant's filing.
 - (3) Transmission Studies and related information, including:
 - (i) The applicant's long-term transmission plan, conducted by applicant, or the RTO, ISO or other relevant entity;



- (ii) Transmission constraints by path, element or other level of comparable detail that have occurred and/or are known and expected to occur, and any proposed mitigation including transmission construction plans;
 - (iii) Levels of congestion, if available;
 - (iv) Relevant system impact studies for the generation interconnections, already completed;
 - (v) Other information pertinent to showing whether transfer capability is available; and
 - (vi) The appropriate link to applicant's OASIS, if any, from which a qualifying facility may obtain applicant's available transfer capability (ATC) information.
- (4) Describe the process, procedures and practices that qualifying facilities interconnected to the applicant's system must follow to arrange for the transmission service to transfer power to purchasers other than the applicant.
- This description must include the process, procedures and practices of all distribution, transmission and regional transmission facilities necessary for qualifying facility access to the market.
- (5) If qualifying facilities will be required to execute new interconnection agreements, or renegotiate existing agreements so that they can effectuate wholesale sales to third-party purchasers, explain the requirements, charges and the process to be followed. Also, explain any differences in these requirements as they apply to qualifying facilities compared to other generators, or to applicant-owned generation.
 - (6) Applicants seeking a Commission finding pursuant to § 292.309(a)(2) or (3), except those applicants located in ERCOT, also must provide evidence of 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, to buyers other than the utility to which the qualifying facility is interconnected. In demonstrating that a meaningful opportunity to sell exists, provide evidence of transactions within the relevant market. Applicants must include a list of known or potential purchasers, e.g., jurisdictional and non-jurisdictional utilities as well as retail energy service providers.

- (7) Signature of authorized individual evidencing the accuracy and authenticity of information provided by applicant.
- (8) Person(s) to whom communications regarding the filed information may be addressed, including name, title, telephone number, and mailing address.

§ 292.311 Reinstatement of obligation to purchase.

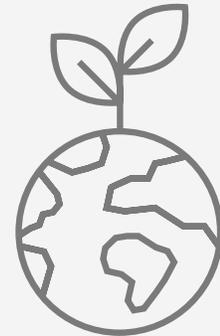
At any time after the Commission makes a finding under §§ 292.309 and 292.310 relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in § 292.309(a), (b) or (c) are no longer met. After notice, including sufficient notice to potentially affected electric utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in § 292.309(a), (b), or (c) which relieved the obligation to purchase, are no longer met.

§ 292.312 Termination of obligation to sell to qualifying facilities.

- (a) Any electric utility may file an application with the Commission for relief from the mandatory obligation to sell under this section on a service territory-wide basis or a single qualifying facility basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in paragraphs (b)(1) and (b)(2) of this section have been met. After notice, including sufficient notice to potentially affected qualifying facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in paragraphs (b)(1) and (b)(2) of this section have been met.
- (b) After August 8, 2005, an electric utility shall not be required to enter into a new contract or obligation to sell electric energy to a qualifying small power production facility, an existing qualifying cogeneration facility, or a new qualifying cogeneration facility if the Commission has found that;
- (1) Competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and
 - (2) The electric utility is not required by State law to sell electric energy in its service territory.

§ 292.313 Reinstatement of obligation to sell.

At any time after the Commission makes a finding under § 292.312 relieving an electric utility of its obligation to sell electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for



an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in Paragraph (b)(1) and (b)(2) of this section are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to sell electric energy under this section if the Commission finds that the conditions set forth in paragraphs (b) (1) and (b)(2) of this section are no longer met.

§ 292.314 Existing rights and remedies.

Nothing in this section affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or nonregulated electric utility on or before August 8, 2005, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

§ 292.401 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.402 Waivers.

- (a) State regulatory authority and nonregulated electric utility waivers. Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of subpart C (other than § 292.302 thereof).
- (b) Commission action. The Commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

- (a) Applicability. This section applies to qualifying facilities, other than those described in paragraph (b) of this section. This section also applies to qualifying facilities that meet the criteria of section 3(17)(E) of the Federal Power Act (16 U.S.C. 796(17) (E)), notwithstanding paragraph (b).
- (b) Exclusion. This section does not apply to a qualifying small power production facility with a power production capacity which

exceeds 30 megawatts, if such facility uses any primary energy source other than geothermal resources.

- (c) General rule. Any qualifying facility described in paragraph (a) of this section shall be exempt from all sections of the Federal Power Act, except:
 - (1) Sections 205 and 206; however, sales of energy or capacity made by qualifying facilities 20 MW or smaller, or made pursuant to a contract executed on or before March 17, 2006 or made pursuant to a state regulatory authority's implementation of section 210 the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 824a-1, shall be exempt from scrutiny under sections 205 and 206;
 - (2) Section 1-18, and 21-30;
 - (3) Sections 202(c), 210, 211, 212, 213, 214, 215, 220, 221 and 222;
 - (4) Sections 305(c); and
 - (5) Any necessary enforcement provision of part III of the Federal Power Act (including but not limited to sections 306, 307, 308, 309, 314, 315, 316 and 316A) with regard to the sections listed in paragraphs (c)(1), (2), (3) and (4) of this section.

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act of 2005 and certain State laws and regulations.

- (a) Applicability. This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.



- (b) Exemption from the Public Utility Holding Company Act of 2005. A qualifying facility described in paragraph (a) of this section or a utility geothermal small power production facility shall be exempt from the Public Utility Holding Company Act of 2005, 42 U.S.C. 16,451–63.
- (c) Exemption from certain State laws and regulations.
 - (1) Any qualifying facility described in paragraph (a) of this section shall be exempt (except as provided in paragraph (c)(2) of this section) from State laws or regulations respecting:
 - (i) The rates of electric utilities; and
 - (ii) The financial and organizational regulation of electric utilities.
 - (2) A qualifying facility may not be exempted from State laws and regulations implementing subpart C.
 - (3) Upon request of a state regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in paragraph (b)(1) of this section.
 - (4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

I. State PURPA Resources

- **NRRI PURPA Tracker:** The National Regulatory Research Institute, the research arm to the National Association of Rural Utility Commissioners and its members, tracks PURPA implementation by state, including information related to: PURPA contract terms, thresholds to be deemed a QF, method for determining avoided cost rates, avoided cost rates, the amount of existing QF capacity, and relevant state developments or state public utility commission dockets.
 - Note: this resource was last updated August 2020.
- **Energy State Bill Tracking Database:** The National Conference of State Legislatures provides access to a searchable database of state energy legislation, both under consideration and currently enacted. This tool is relatively new, but is available for bills from 2015 and later. The tool allows users to search by keyword or by bill status, bill number, year, and author; users can also filter results by topic or state.
- **DOE.gov:** The U.S. Department of Energy website maintains a PURPA page, including links to PURPA practice manuals and other background information. Additionally, DOE has

published three lists of PURPA-covered utilities to better serve the “states must consider...” PURPA provisions in the Energy Policy Act of 2005 and Energy Independence and Security Act of 2007 related to federal standards under PURPA Title I:

- **2009 List of U.S. Electric Utilities Covered by Title I of PURPA**
- **2008 List of U.S. Electric Utilities Covered by Title I of PURPA**
- **2006 List of U. S. Electric Utilities Covered by Title I of PURPA**
- Note: DOE does not intend to update these lists unless Congress enacts new federal standards.
- **EIA.gov:** The U.S. Energy Information Administration website maintains a repository of independent statistical analyses and informational reports. Data on individual electric utility’s retail sales is collected by the EIA through its Form EIA-826 “Monthly Electric Utility Sales and Revenue Report with State Distributions,” and made available in spreadsheet format by utility and sales year. This resource may be useful for determining whether an electric utility is subject to PURPA Title I (a covered utility is one that has more than 500 million kilowatt-hours of retail sales per year), or generally for informational purposes.
- State public utility commission websites: Some states have dedicated PURPA pages on their commission’s website that compile resources such as docket/order links related to PURPA implementation, avoided cost rates by utility, or recently-approved PURPA contracts. See, for example, the **Michigan PSC** and **Oregon PUC**.





II. Federal PURPA Resources

In addition to the DOE and EIA websites listed above, the following resources provide publicly-accessible information regarding federal PURPA regulations and enforcement.

- PURPA practice manuals:
 - [EPA Act 2005 Manual](#)
 - [EISA 2007 Manual](#)
 - [March 2014 PURPA Title II Manual](#)
- [FERC.gov](#): FERC's PURPA page contains detailed information regarding how to obtain QF status, as well as certification and recertification requirements, including instructions on how to fill out and submit a FERC Form 556. The page also contains instructions on how to protest a FERC Form 556. Finally, the page provides links to the major orders and related issuances:
 - [Order No. 872 Fact Sheet](#)
 - [Order No. 872 News Release and Staff Presentation](#)
 - [Order No. 872-A News Release](#)
- [Smithsonian Institute](#): The Smithsonian Museum of American History has published articles regarding the historic context of PURPA in a series entitled "Powering The Past: A Look Back." In particular, the series explores the emergence and proliferation of electric utilities in the United States, the energy crisis of the 1970s, the reforms introduced by PURPA and the National Energy Act of 1978, and the evolution of organized energy markets.
- Additional information related to PURPA and the policy positions of the Manual sponsors are available at the sponsors' websites:
 - [American Public Power Association \(APPA\)](#)
 - [Edison Electric Institute \(EEI\)](#)
 - [National Association of Regulatory Utility Commissioners \(NARUC\)](#)
 - [National Rural Electric Cooperative Association \(NRECA\)](#)

