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# PURPA TITLE II COMPLIANCE MANUAL

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American Public Power Association (APPA)

Edison Electric Institute (EEI)

National Association of Regulatory Utility Commissioners (NARUC)

National Rural Electric Cooperative Association (NRECA)

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## Preface

This manual was sponsored by the American Public Power Association (APPA), the Edison Electric Institute (EEl), 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. This manual was prepared by Robert E. Burns, an independent consultant and attorney, who previously was a Research Specialist at The Ohio State University, where he spent more than 25 years at the National Regulatory Research Institute; and Dr. Kenneth Rose, an independent consultant and Senior Fellow with the Institute of Public Utilities at Michigan State University.

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# I Introduction

## A. Historical Context

The Public Utility Regulatory Policies Act of 1978 (PURPA) was passed as part of a package of legislation known as the National Energy Act of 1978<sup>1</sup> that was intended to address the ongoing “energy crisis” of the time. Among other goals, PURPA was intended to encourage conservation, reliability, and efficiency in the delivery and generation of electricity, and to do so with “equitable retail rates for electric consumers.”<sup>2</sup> The primary concerns at the time (and still today, albeit in slightly different circumstances) were the increasing amounts of imported oil, the national security risks those imports imposed, and the security of natural gas supply.<sup>3</sup> Conservation by electric utilities of oil and natural gas was important since petroleum-based liquids accounted for more than 16 percent and natural gas was almost 14 percent of the fuel used to generate electricity (on a total kilowatthour basis) in 1978.<sup>4</sup>

In general, we can look back at PURPA and the other components of the National Energy Act of 1978 and see the same goals and conflicts that face policy makers today. These goals include national security, economic growth, reasonable consumer prices for energy, environmental protection, and so on; as well as the conflicts between and among economic growth and environmental protection, retail energy prices and consumer and producer incentives, and technology mandates and pricing mechanisms.

PURPA’s six titles dealt with a wide range of utility issues including ratemaking standards and policies for electric and natural gas utilities, hydroelectric power, and crude oil transportation. Of principal concern in this manual is Title II of PURPA, which had the nonspecific and perhaps unhelpful title, “Certain Federal Energy Regulatory Commission and Department of Energy Authorities.” A brief synopsis of Title II is provided in the next section, followed by a more complete summary of the current implementation regulations.

## B. Key Features of Title II of PURPA

This is a brief summary of the original PURPA provisions, some important definitions, changes to PURPA in 2005, and recent enforcement action by the Federal Energy Regulatory Commission (FERC). More detail is provided in subsequent sections of this Manual.

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<sup>1</sup> In addition to PURPA (Pub.L. 95–617, November 9, 1978), the other four parts of the National Energy Act of 1978 were Energy Tax Act (Pub.L. 95–618), National Energy Conservation Policy Act (NECPA) (Pub.L. 95–619), Power Plant and Industrial Fuel Use Act (Pub.L. 95–620), and the Natural Gas Policy Act (Pub.L. 95–621).

<sup>2</sup> From the “Findings” section at the beginning of PURPA.

<sup>3</sup> This may seem puzzling to some three-and-a-half decades later, but there was real concern at the time that the U.S. was beginning to run low on natural gas supply.

<sup>4</sup> Based on data from the U.S. Energy Information Administration (EIA). In later years, petroleum use dwindled to less than one percent of the fuel used to generate electricity in the U.S. Through the late 1970s and 1980s, coal displaced petroleum and natural gas for electric generation.

### *Original PURPA Provisions for QFs and Avoided Cost*

- Under the original terms of PURPA, **Qualifying Facilities (QFs)** are defined as qualifying cogeneration facilities or qualifying small power production facilities that have a right to be served by, and sell to, their host electric utilities at the utility's "avoided cost."
- **Cogeneration facilities** are those which produce electric energy and steam or forms of useful energy (such as heat), which are used for industrial, commercial, or cooling purposes (often referred to today as combined heat and power, or CHP facilities). There is no maximum size limitation for PURPA qualification for cogeneration facilities. The Energy Policy Act of 2005 (EPAct 2005) prohibits so-called "PURPA machines" (essentially an electric generator that produces only a small token (or trivial) amount of useful thermal energy) by requiring that useful energy must be produced.
- **Small power production facilities** are defined as facilities which use biomass, waste, or renewable resources, including wind, solar energy, and water, to produce electric power, and which, together with other facilities at the same site, have a generating capacity equal to or less than 80 MW.
- The original PURPA "**must purchase**" obligation applies to all electric utilities, including IOUs, municipals, rural cooperatives, public utility districts (PUDs), water districts, the Tennessee Valley Authority, and each federal power marketing authority, unless FERC grants a waiver. FERC requires that host utilities must purchase at rates equal to the host utility's full **avoided cost** "*the incremental cost to the electric utility of electric energy or capacity or both which, BUT FOR the purchase from the QF or QFs, such utility would generate itself or purchase from another source*" (18 CFR sec. 292.101(b)(6)).
- Prior to EPAct 2005, states and non-regulated utilities always determined avoided cost, either by administratively determining them or through market-based methods. Methods of calculating administratively determined/market-based avoided costs (still used in many instances) include the proxy plant method, the peaker method, the partial displacement differential revenue requirement method, fuel index rates, or auction/request for proposals (RFP).
- The original PURPA "**must sell**" obligation requires each host electric utility to sell to any QF any energy and capacity requested by the QF. The host electric utility is required to provide that electric service to a QF at rates that are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers.

### *EPAct 2005 Changes to the "Must Purchase" Obligation*

- EPAct 2005 provided a new PURPA section (210(m)) that requires FERC to 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. Specifically, no utility must-purchase obligation exists if FERC finds that the QF has nondiscriminatory access to:
  - (1) independently administered, auction-based day-ahead and real-time wholesale markets and wholesale markets for long-term sales of capacity and energy (e.g., MISO, PJM, ISO-NE, NYISO), or
  - (2) a regional transmission organization (RTO) with competitive wholesale markets, or

- (3) wholesale markets that are comparable to (1) or (2).
- FERC, by its rulemaking in Order 688, determined that MISO, PJM, ISO-NE, the NYISO, and ERCOT provide wholesale markets which meet the statutory criteria for member utilities to qualify for relief from the mandatory must-purchase obligation. Order 688 also created a rebuttable presumption that QFs larger than 20 MW have non-discriminatory access to at least one of these competitive markets. FERC did not terminate the must-purchase obligation, however. Electric utilities must file applications for relief and QFs in the above markets may, under the rule, rebut the presumption of access because of operational characteristics or transmission constraints.

### *EPAct 2005 Changes the “Must Sell” Obligation*

- Under EPAct’s PURPA amendments, the mandatory obligation to sell can be terminated if FERC finds that competing retail electric suppliers are willing and able to sell and deliver electric energy to the QF, AND the electric utility is not required by state law to sell electric energy in its service territory. There are many instances where the obligation to sell might persist even though there would be no obligation to purchase, for example, in states with retail price regulation that are also in an above-mentioned RTO.
- Left unaffected are any rights or remedies of any party under contract or obligation, in effect or pending approval of a state regulatory commission, or non-regulated utility at the time of EPAct 2005’s enactment, to purchase from or sell electric energy or capacity to a QF.

### *FERC Enforcement Provision*

- Under section 210 (H)(2)(A), (B) of PURPA, FERC has discretionary power to enforce the PURPA rules against the state commissions and non-regulated utilities; that is, to require that state commissions and non-regulated utilities comply with FERC’s PURPA rules. Until recently, this enforcement provision was dormant. In a series of recent cases, however, the dormant enforcement clause became active for the first time since PURPA was enacted. A summary of these recent cases are in Part III of this Manual.

## **C. PURPA Compliance and Implementation: Frequently Asked Questions**

### **1. Background**

#### **a. What is PURPA?**

The Public Utility Regulatory Policies Act of 1978 (PUPRA) was passed as part of the legislation known as the National Energy Policy Act. The purpose of PURPA was to encourage conservation, reliability, and efficiency in the delivery and generation of electricity, and to do so with equitable retail rates for electric consumers. In the case of PURPA sections 201 and 210, the purpose was to promote certain small renewable power producers and cogenerators, and to do so in a manner that did not adversely affect retail rates for other electric consumers.

The different titles of PURPA addressed a variety of areas. There were six titles on a variety of utility issues, including ratemaking standards for electric and natural gas utilities (Title I). Of principal concern are the Title II provisions dealing with qualifying facilities and avoided costs, which are covered in PURPA sections 201 and 210, respectively.

See [Historical Context](#).

**b. What is the historical context of PURPA?**

PURPA was enacted as part of the National Energy Policy Act of 1978, which was a response to the energy crisis of the 1970s. This crisis included the 1973-74 oil embargo and the mid- to late-1970s' natural gas shortages. One reaction to this extended crisis was the enactment of the Fuel Use Act of 1978, which prohibited construction of new natural gas-fired electric generation. PURPA Title I measures were meant to encourage rate reform that would set in motion conservation and efficiency, for the reliable delivery and generation of electricity. Section 201 and 210 provisions of PURPA, encouraged development of certain small power renewable production and cogeneration facilities, and were enacted as a part of this broader initiative.

**c. What are some of the major changes to PURPA sections 201 and 210 since their enactment?**

The Energy Policy Act of 2005 (EPAAct 2005) made several major changes to PURPA sections 201 and 210. Among those changes was the elimination of the ownership requirement. Prior to the enactment of EPAAct 2005, no more than 50 percent of a QF could be owned by an electric utility. That ownership requirement was eliminated and now electric utilities can have 100 percent ownership in QFs.

See [FERC Implementation Orders and Actions](#), after fourth paragraph.

EPAAct 2005 also changed the criteria for determining whether a new cogeneration facility, that is, one that was not one prior to the enactment of EPAAct 2005, is a qualified facility in order to disqualify so-called "PURPA machines" (essentially an electric generator that produces only a small token (or trivial) amount of useful thermal energy).

See [§292.205\(d\) Criteria for new cogeneration facilities](#).

EPAAct 2005 provides that the "must-purchase" and "must-sell" PURPA obligations can be waived in the presence of certain conditions. In the case of the "must-purchase" obligation, EPAAct 2005 requires FERC to excuse the host utilities from entering new purchase or contract obligations if there is access to sufficiently competitive markets for the QF to sell power. For more information on a "must purchase waiver" see this link: [EPAAct 2005 – Opt-Out Provisions in Competitive Markets](#).

EPAAct 2005 also provides a waiver from the "must-sell" obligation for a host utility 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.

See [EPAAct 2005 – Opt-Out Provisions in Competitive Markets](#).



## 2. Foundational principles

### a. What is a Qualifying Facility (QF)?

A qualifying facility is either a cogeneration facility or a small power production facility that meets the requirements of PURPA section 201. As such, a qualifying cogeneration facility is defined as equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) that are used for industrial, commercial, heating or cooling purposes, through the sequential use of energy. There are additional operating and efficiency standards to be a qualifying cogeneration facility.

See [Definition of Qualifying Facility and Cogeneration Facility \(§292.101\)](#).

A qualified small power production facility is a biomass, waste, renewable resources, geothermal resources, or any combination, whose capacity owned by the same entity (or entities) or its affiliate(s) on the same site, may not exceed 80 MW. There is a limited exception to the size criteria for certain qualified small power production facilities.

See [Criteria for qualifying small power production facilities \(§292.204\)](#).

There are special criteria and provisions for small hydroelectric facilities.

See [Special requirements for hydroelectric small power production facilities located at a new dam or diversion \(§ 292.208\)](#).

### b. How is a QF certified?

The QF status of an existing or proposed facility may be self-certified by the owner or operator of the facility by successfully completing a FERC Form 556 and filing that form electronically with Commission. FERC has also issued an exemption for small power production and cogeneration facilities with 1 MW or less of net production capacity. Alternatively, the QF might seek an optional FERC certification. Under those procedures, the applicant files for a determination by FERC that the facility meets the requirements for QF status. QFs with 1 MW of capacity or less are not required to make any filings to become a QF. All applicants for QF notification (those that are larger than 1 MW in size) are required to serve a copy of their Form 556 on the affected utilities and state regulatory authorities.

See [What Is a Qualifying Facility?](#)

FERC or any person, including the utility, may challenge a generator's QF status and may seek revocation before FERC of that facility's QF status.

See [\(d\) Revocation of qualifying status](#).

### c. What is the impact of QF status on regulation under the Federal Power Act, the Public Utility Holding Company Act of 2005, and applicable state law?

QFs receive relief from several regulatory burdens. Cogeneration QFs of any size, small power production facilities of 30 MW or less, geothermal and biomass small power production facilities of any

size, and certain other small power production facilities are exempt from the Public Utility Holding Company Act of 2005 and from most of the Federal Power Act (except sections 205 and 206, unless they are 20 MW or smaller and making QF sales pursuant to certain existing contracts or pursuant to a state commission's implementation of section 210 of PURPA). These same QFs are also exempt from applicable state laws and regulations respecting the rates and financial and organizational aspects of utilities.

See [Why Become a QF?](#)

**d. Who is subject to PURPA section 210? What is an electric utility? Is there a size threshold?**

Technically, any electric utility is subject to PURPA section 210. According to PURPA section 201, an "electric utility" means any person, state agency, or federal agency, which sells electricity. The term includes the Tennessee Valley Authority, but does not include any federal power marketing agency. There is no utility size threshold in the statute. Nevertheless, FERC has streamlined some of the cost data regulations for small utilities.

See text box [on page 43](#).

**e. What are the key obligations of utilities under PURPA section 210?**

There are three key utility obligations under PURPA section 210. Unless exempted because of the waiver provisions in EPAct 2005, the first two obligations are (1) the obligation to purchase from qualifying facilities any energy and capacity which is made available from a qualifying facility, and, (2) the obligation to sell to any qualifying facility. A third obligation is to interconnect with the qualifying facility.

See [Electric utility obligations under this subpart \(§ 292.303\)](#).

**f. Who Implements PURPA sections 201 and 210?**

The FERC issued regulations implementing PURPA sections 201 and 210. The section 201 regulations define "qualifying small power production facility" and "qualifying cogeneration facility" and set out the requirements for each.

See [FERC Regulation Subparts A and B: Definitions and Criteria for Qualification](#).

While FERC has also issued regulations on PURPA section 210, as originally implemented, FERC rules require state public service commissions and non-regulated utilities (primarily rural cooperatives and municipalities not regulated by state authority) to set rates for the host utility to purchase power from a qualifying facility. State regulatory commissions and non-regulated utilities, under FERC regulations, also have the responsibility to determine the cost of interconnecting a qualifying facility with the utility system, and to specify the manner and time period in which the qualifying facility will reimburse the utility for this interconnection cost. Also, as originally implemented, FERC rules gave states and non-regulated utilities the responsibility to establish rates for the sale of supplementary, back-up,

maintenance, and interruptible power to QFs. State commissions and non-regulated utilities have section 210 implementation plans in accordance with FERC rules.

See [FERC Regulation Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978 \(§ 292.301\)](#).

**g. Who enforces PURPA and what are the processes for obtaining enforcement?**

Most PURPA implementation questions are handled by the state commissions and non-regulated utilities. 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 commission and/or non-regulated utility. State commissions and non-regulated 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 commission's decision or interpretation in implementing a PURPA QF regulation. Access to FERC and the federal courts is limited to complaints that a state commission or a non-regulated 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 commissions and non-regulated utilities to comply with its rules. FERC typically issues declaratory orders to find a state commission or non-regulated utility failed to comply. FERC may bring an action in federal court if a state commission or non-regulated utility fails to comply with the requirements of its rules. Of great interest is the recent plethora of cases brought under PURPA section 210 (h)(2)(B), which allows any electric utility or qualifying facility to petition FERC for an enforcement action against a state commission or non-regulated utilities for failing to comply with FERC rules. State commissions and non-regulated utilities have some flexibility for implementation within FERC rules; this means the standard for an enforcement action is higher for a failure to implement the PURPA rules in one manner or another. The standard for enforcement is a failure to comply with FERC rules. If FERC does not initiate an enforcement action within 60 days, the petitioner may bring an action in federal court, and the federal court may issue such injunctive relief or other relief as appropriate. FERC may intervene as a matter of right.

See Part [III Recent PURPA-Related Cases](#).

**h. What is the utility interconnection obligation? And can the utility charge for interconnection costs?**

A QF has the right to interconnect with a utility and the utility is obligated to interconnect with a QF provided the QF pays the utility an interconnection fee which is assessed on a non-discriminatory basis with respect to other customers with similar load characteristics. The interconnection fee can include certain interconnection costs. The state commission or non-regulated utility must determine the manner for paying the recoverable interconnection costs, which may include reimbursement over a reasonable time. Interconnection costs mean the reasonable cost of connecting, switching, metering, upgrades to transmission, upgrades to distribution, safety provisions, and administrative costs incurred by the utility directly related to interconnecting to the QF. (These costs can vary according to the

utility's anticipated purchase and/or sell obligation.) Interconnection costs are recoverable to the extent they would not have been incurred had the utility not interconnected, but, instead, generated an equivalent amount of electric energy or capacity or had purchased them from another source.

See [Interconnection costs \(§ 292.306\)](#).

**i. What is the utility sales obligation? Can a utility disconnect a QF customer if it doesn't pay for back-up services? What is the EPAct 2005 waiver provision?**

The utility obligation to sell to QFs requires utilities to sell supplemental power, back-up power, maintenance power, and interruptible power to a QF on a non-discriminatory basis in comparison to rates for sales to the utility's other customers. Rates based on accurate data and consistent with system-wide costing principles are not be considered to discriminate against the QF to the extent that the rates apply to other customers with similar load or other cost-related features. If a QF does not pay for back-up services, the utility can disconnect the customer. However, there is a problematic Iowa case where FERC held a customer that did not pay interconnection fees and retail services should not be disconnected without first obtaining a FERC waiver. This case appears to be an aberration. Even so, abundant caution should be used in disconnecting a QF for failing to pay fees and services. It might be advisable to contact FERC staff before such a disconnection is performed.

See [Rates for sales \(§ 292.305\)](#), also see discussion of the Iowa case (Midland Power Cooperative) in Part III [Recent PURPA-Related Cases](#).

Precedents exist for a waiver to be granted to generation-transmission (G&T) cooperatives from the utility obligation to sell power 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. G&T utilities usually are allowed to stand in place of the distribution cooperative for the purchase of qualifying facility power, and the G&T cooperative does so at its own avoided cost. See *Western Farmers Electric Cooperative*, Order Granting Petition for Partial Waiver, Docket EL06-6-000 (June 15, 2006). This also applies to Municipal Joint Action Agencies, which are also granted a waiver to purchase power from QFs, which their member municipalities would otherwise have been required to purchase, so long as the member municipality makes sales to the QFs that the Municipal Joint Action Agency would otherwise be required to make. See *Missouri River Energy Services*, Docket EL 13-80-000, 145 FERC para. 62,022 (October 9, 2013).

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. Rights and obligations of any part under an existing contract or obligation in effect or pending approval at the time of EPAct 2005's enactment are unaffected.

See [EPAct 2005 – Opt-Out Provisions in Competitive Markets](#).

**j. What is the utility must-purchase obligation?**

Unless otherwise exempted, an electric utility must purchase energy and capacity made available from a QF at that utility's avoided costs. Any electric utility to which a QF can deliver power must purchase the power at its own avoided cost, even if it is not the utility to which the QF is directly interconnected.

See [Obligation to purchase from qualifying facilities](#).

However, after August 8, 2005, electric utilities were no longer 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 (1) an independently administered, auction-based day-ahead and real-time wholesale market for the sale of electric energy, *and* wholesale markets for long-term sales of capacity and electric energy; or (2) transmission and interconnection services that are provided by FERC-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers, *and* 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; 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 (1) and (2).

See [Termination of obligation to purchase from qualifying facilities \(§ 292.309\)](#) and [Procedures for utilities requesting termination of obligation to purchase from qualifying facilities \(§ 292.310\)](#).

**3. What is the history of avoided costs? What are avoided costs? Who sets or determines avoided costs? Does the Qualifying Facility have options to choose the term of a contract or the method of how to determine avoided costs?**

PURPA section 210(b) states that purchase price rates must be just and reasonable to the electric consumers of the electric utility and in the public interest; and must not discriminate against cogenerators or small power producers. Rates also must not exceed the incremental cost to the utility of alternative electric energy. In implementing PURPA, FERC opted in section 292.101(b)(6) that rates must equal the utility's full avoided costs; that is, the incremental costs to the electric utility of electric energy or capacity, or both, which, but for the purchase from the QF or QFs, the utility would generate itself or purchase from another source. PURPA does not require and does not permit states to require payments above full avoided costs.

See [Determining Avoided Cost](#).

The state commission or the non-regulated utility determines the method for calculating avoided costs. So long as the method fits the definition and is non-discriminatory, the determination is considered to be consistent with FERC rules. The QF has the option of negotiating a contract with the electric utility in lieu of the administratively determined or market-determined avoided cost. The term of the contract is subject to negotiation, although most QFs seek a contract term long enough to obtain financing for their plant. If there is no contract and the QF is providing energy or capacity pursuant to a legally enforceable

obligation over a specified term, the rates for the purchase over that term will be based either (1) on the avoided cost calculated at the time of delivery or (2) the avoided costs calculate at the time the obligation is incurred. Picking option 1 or 2 is at the discretion of the QF, and must be exercised prior to the beginning of the specified term. The rules are silent as to whether the QF or utility gets to determine the specified term.

See subsection [\(d\) Purchases “as available” or pursuant to a legally enforceable obligation.](#)

**a. What is the standard tariff obligation for QFs of 100 kW and below?**

Each electric utility is required to have standard offer tariffs for purchases from QFs with design capacity of 100 kW or less. In addition, it is also permissible that standard offer tariffs be available for purchases from QFs of greater than 100 kW.

See subsection [\(c\) Standard rates for purchases.](#)

**b. What are some of the options for calculating and determining avoided costs?**

Several methods have been used by states for long-term contracts to establish avoid costs. These methods have generally satisfied FERC requirements and have been in use for many years.

See discussion beginning [on page 35](#). The general discussion of avoided cost begins on page [33](#), [Determining Avoided Cost](#).

**c. Explain net metering as an option for avoided cost purchases.**

Net metering is not a method for calculating avoided costs. Rather, it is widely used as a means to compensate small-scale renewable QFs. Net metering’s availability varies widely from state to state. Net metering is an option that electric utilities may offer—it is not required, unless otherwise mandated by state law.

See [Net Metering](#).

**d. Can avoided costs be resource specific?**

Yes. In addition to the statement in the PURPA regulation on standard offer tariffs [which says that standard offer rates may differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies (292.304(b)(ii))], there is a line of FERC cases—including the Clarification Order for California Public Utilities Commission, 133 FERC para. 61,059 (October 21, 2010)—that found that the concept of multi-tiered avoided-cost rate structures for different resources can be consistent with the avoided-cost rate requirements of PURPA and FERC regulations.

See [Feed-in Tariffs](#).

**e. What about complications in calculating avoided costs, such as determining capacity value?**

Determining avoided capacity costs is particularly nettlesome as it is difficult to know what type of future capacity is being avoided, when, and at what cost. This is further complicated by the fact that base load capacity is large and “lumpy,” while most QFs come on in small increments. The various methods of determining avoided cost solve this problem in different ways.

See discussion of avoided cost calculation methods beginning [on page 35](#). The general discussion of avoided cost is on [page 33, Determining Avoided Cost](#).

**f. What happens if the utility does not need energy or capacity?**

If the utility can demonstrate that it does not need capacity over its planning horizon, then the avoided cost value should include no avoided capacity charge. It is presumed that the utility needs energy, unless the additional energy from a QF puts the utility in a minimum generation situation, where base load capacity (with long ramping times) is being shut off. In that case, the avoided cost of energy is zero, or negative, and purchase is not required.

See subsection [\(f\) Periods during which purchases not required](#).

**g. Whose avoided cost is used if a utility has an all-requirements contract with another utility or supplier?**

In this case, the avoided cost of the all-requirements supplier is used. FERC has consistently held that the avoided cost of an all-requirements utility customer are those of its all-requirements supplier. See *Western Farmers Electric Cooperative*, in FAQ 2.i., above.

**h. What happens when a long-term existing contract with a QF expires?**

The utility would presumably still have a legally enforceable obligation to purchase from the QF at the utility's determined avoided cost (which could be at the standard offer tariff, only if applicable) 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. Otherwise, this legally enforceable obligation remains in place unless and until the utility seeks and is granted applicable FERC waivers to its obligation to purchase from, and/or its obligation to sell to, the QF. In the meantime, the utility and QF are free to negotiate a new contract, if they so desire.

**i. What happens when a state changes its avoided cost determination method or moves from a standard offer tariff for more than 100 kW to another method?**

The new method applies to new QFs, however, caution must be exercised. The new method cannot take effect until it is actually approved by the state commission or non-regulated utility, and not retroactively. Until the new method takes effect, QFs can create legally enforceable obligations to be covered by the old method. QFs also might seek and be able to create legally enforceable obligations to be covered by the old method. See the [discussion of the Idaho cases](#), which should be limited to their facts, not generalized to all cases.

See section [III Recent PURPA-Related Cases](#).

**j. Where are questions about avoided cost litigated?**

Questions about the actual avoided-cost determinations are litigated before the state commissions or the state courts with applicable jurisdiction for non-regulated utilities. Questions regarding whether a method of avoided-cost determination is consistent with PURPA and FERC implementation rules are litigated before FERC or an applicable federal court.

See part [III Recent PURPA-Related Cases](#).

**k. May the QF and utility negotiate a rate other than avoided cost? If so, when, how, or why?**

Yes, although the negotiated rate should reflect avoided cost at least at its starting point. It may diverge, however, to accommodate the mutual needs of the utility and the QF. The contract may be negotiated or renegotiated at any time, although, in the past, it has typically been negotiated by utilities and QFs as the QF is gathering the assurances necessary to finance its project. There is no reason such contracts cannot be negotiated or renegotiated as existing QF term contracts expire or are about to do so. The uncertainty that exists about the term and the status of legally enforceable obligations and, when applicable, the possibility that a utility might apply for a waiver might create a backdrop that could encourage such negotiations to occur.

**l. What if a utility and the QF agree to wheel to a third-party utility?**

If a QF agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from a QF may transmit the energy or capacity to another electric utility.

See [Transmission to other electric utilities](#).

There is nothing in the regulations to prohibit the wheeling utility from charging a non-discriminatory open access transmission rate for its wheeling services.

**m. What is the obligation of a utility to purchase power from a QF delivered to it even if it is not directly interconnected to the QF?**

Any electric utility to which QF energy or capacity is transmitted is obligated to purchase the energy or capacity as if the QF were supplying directly to the utility. The rate for purchase is equal to the utility's avoided cost. Note that the energy delivered is adjusted to reflect line losses that occur, and that the purchasing utility does not pay any of the transmission (wheeling) charges.

See [Transmission to other electric utilities](#).

**n. What if the QF wants to sell into the market? Must the utility wheel? If so, can the utility charge for wheeling? Is there any effect on the QF's jurisdictional status?**

Any obligation to provide transmission services under this scenario would come from the filed Open Access Transmission Tariff (OATT), not from the PURPA regulations. If the utility provided transmission, it would be allowed to charge a non-discriminatory transmission charge. The fact that a QF sold into a market is not in and of itself sufficient to determine the issue of its jurisdictional status, although it would be evidence that could show that the QF has access to competitive markets, should the utility wish to press forward with a petition for a waiver from the obligation to purchase.

**o. What is the waiver provision for the obligation to sell?**

See [Termination of obligation to sell to qualifying facilities \(§ 292.312\)](#).



Special provisions allow a generation and transmission cooperative to undertake the obligation to purchase on behalf of its member cooperatives, so long as their member cooperatives undertake the obligation to sell. Similar special provisions are also available to Municipal Joint Action Agencies.

**p. What is the impact on existing QFs' ability to get waivers?**

Utilities must petition FERC for a waiver in order to get FERC determination that a waiver is granted. Existing QFs are affected as their existing contracts or existing legally enforceable obligations to serve, which can be determined if for a specific term, expire. Determining when existing QFs that sell on an "as-available" basis without a specified term would be subject to a waiver provision and could be more contentious.

See [Termination of obligation to sell to qualifying facilities \(§ 292.312\)](#), [Reinstatement of obligation to sell \(§ 292.313\)](#), and [Existing rights and remedies \(§ 292.314\)](#).

## **D. Regulatory Background and Authority Under PURPA Sections 201 and 210**

Congress enacted PURPA sections 201 and 210 to encourage cogeneration and small power production by requiring utilities to purchase power at special rates and terms from cogenerators and small power producers that are identified as being qualifying facilities under rules promulgated by FERC. To qualify under these rules, cogenerators and small power producers must meet several conditions.

Section 201 defines a "cogeneration facility" as a facility which produces both electricity and steam or some other useful form of energy, such as heat, which is used for industrial, commercial, heating, or cooling purposes. Section 201 defines a qualifying small power production facility as a site that has a combined capacity not greater than 80 MW that uses wind, solar, biomass, waste, geothermal, or some other renewable resource (including hydroelectric power) as a primary energy source. As for a cogenerator, the first condition is that the facility must meet minimum efficiency standards. The second condition concerns the facility ownership. When originally enacted, less than 50 percent of the cogenerator facility's equity could be held by an electric utility or its affiliate, otherwise, the facility does not qualify. Small power production facilities, in order to qualify, must have a generation capacity less than or equal to 80 MW and must meet the same ownership criteria as qualifying cogeneration facilities.

FERC rules do not apply to cogeneration or small power facilities whose construction commenced prior to the enactment of PURPA on November 9, 1978. There are some limited exceptions to the 80 MW size limit that apply to certain facilities certified prior to 1995 and designated under section 3(17)(E) of the Federal Power Act ([FPA](#)) ([16 U.S.C. § 796\(17\)\(E\)](#)), which have no size limitation. In order to be considered a qualifying small power production facility, a facility must also meet all of the requirements of 18 C.F.R. §§ 292.203(a) ([Requirements for small power production facility qualification \(§292.203\)](#)), if applicable 292.203(c) ([FERC Regulations on hydroelectric small power production facilities](#)), 292.204

([Criteria for qualifying small power production facilities \(§292.204\)](#)) for size and fuel use, and be certified as a QF pursuant to 18 C.F.R. § 292.207 (see [Procedures for obtaining qualifying status \(§ 292.207\)](#)).

PURPA section 201 required FERC to issue rules and regulations defining the criteria and producers by which small power producers and cogeneration facilities can obtain qualifying facility status in order to receive the benefits of PURPA section 210. The principal benefit was that the qualifying facility's host utility was required to purchase power from the qualifying facility at the utility's own avoided cost. The host utility was also required to sell electric power to the qualifying facility. In addition, qualifying facilities were exempt from the burden of Public Utility Holding Company Act regulations.

As originally implemented, FERC rules require state public service commissions and non-regulated utilities (primarily rural cooperatives and municipalities not regulated by state authority) to set rates for the host utility to purchase power from a qualifying facility. The rate must equal the cost avoided by the host utility because of its reduced need to generate electricity or to purchase power from another source. Note that avoided cost uses a "but for" test. The important test is based on the cost the host utility would have incurred *but for* its purchase of power from cogenerators and small power producers. The avoided costs that are paid to the cogenerators and small power producers are the costs that the utility avoids, not the cost savings to the ratepayer. In principle, at least, the ratepayer and the utility neither gains nor loses. State commissions and non-regulated utilities are also required to set standard rates for qualifying facilities with generating capabilities of 100 kW or less. These standard rates may differ according to the type of generating technology employed. This is intended to account for differing externalities or the different effect that different types of qualifying facilities would have on the host utility's avoided cost, which will be discussed briefly in the next section and in detail [on page 33](#).

State commissions and non-regulated utilities have the responsibility to determine the cost of interconnecting a qualifying facility with the utility system and to specify the manner and time period in which the qualifying facility will reimburse the utility for this interconnection cost.

As originally implemented, FERC rules gave state commissions the responsibility to establish rates for the sale of supplementary, back-up, maintenance, and interruptible power service to cogenerators and small power producers. These rates must be just and reasonable and in the public interest. The rates may not discriminate against cogenerators or small power producers. The Energy Security Act (section 643(b) of the Energy Security Act of 1980) amendments added provisions concerning geothermal small power production facilities.

PURPA sections 201 and 210 were amended subsequently by section 1253 of EPCA 2005, which added section 210 (m) to PURPA (covered in detail [on page 67](#)). An important provision is the additional requirement for new qualifying cogeneration facilities (essentially cogeneration QFs that were not a QF on or before August 8, 2005, or that had not filed a notice of self-certification or an application for FERC certification before February 2, 2006), see [FERC rule in sec. 205](#). §292.205(d) Criteria for new cogeneration facilities, requires a demonstration that the facility's thermal output is used in a productive and beneficial manner and that the facility's output is used fundamentally for industrial, commercial, residential, or institutional purposes, and is not intended fundamentally for the sale of

electricity. (In other words, the cogeneration facility is not a so-called “PURPA machine” that cogenerates in order to be a qualifying facility fundamentally in order to sell electricity.) EPACT 2005 also included so-called opt-out provisions that can relieve a utility from entering into a new contract or a QF purchase obligation if FERC finds the QF has nondiscriminatory access to one of three categories of markets ([Termination of obligation to purchase from qualifying facilities \(§ 292.309\)](#)). There also are separate provisions that can relieve a utility from its obligation to sell services to its QF ([Termination of obligation to sell to qualifying facilities \(§ 292.312\)](#)). EPACT 2005 also eliminated certain exemptions from regulation that were previously granted to QFs and also eliminated the ownership limitations for QFs.

### **FERC Implementation Orders and Actions**

The original FERC rules implementing sections 210 and 201 of PURPA were issued in FERC Orders 69, 70, 70-A, 70-B, 70-C and 70-D, as well as in Order 135. The most important of these were FERC Orders 69 and 70. In FERC Order 69, dated February 19, 1980, FERC issued rules implementing the avoided-cost rates for sales of electric power between qualifying cogeneration and small power production facilities and electric utilities. It also established exemptions for QFs from most state and federal regulations governing electric utilities. For a full copy of Order 69, see <http://www.ferc.gov/industries/electric/gen-info/qual-fac/orders/order-69-and-erratum.pdf>.

FERC Orders 70, 70-A, 70-B, 70-C, and 70-D establish the criteria and procedures for establishing that a cogeneration or small power production facility is a qualifying facility that qualifies for the special rates, rights, and regulatory exemptions under FERC Order 69. The initial Order 70 was issued on March 13, 1980 and established the initial rules. For a full copy of Order 70, see <http://www.ferc.gov/industries/electric/gen-info/qual-fac/orders/order-70.pdf>. FERC Order 70-A provided that applications for FERC certification of QF status contain a notice for publication in the Federal Register. FERC Order 70-B allowed gas utility holding companies to own QFs. FERC Order 70-B allowed Section 3(a)(3) and 3(a)(5) exempt utility holding companies to own QFs. Section 3(a)(5) of the PUHCA of 1935 grants an exemption to a holding company that does not derive any material part of its income from any public utility company operating in the United States. Section 3(a)(3) of that same act grants an exemption if the utility subsidiary is “functionally related” to the industrial or commercial enterprise’s other businesses. This provision could cover utility subsidiaries that own industrial or commercial enterprise cogeneration facilities. FERC Order 70-D enabled certain “electric utilities” which were not “primarily engaged in either the generation or sale of electric energy” to own up to 100 percent of a QF.

FERC Order 135 implements the Energy Security Act amendments to the Federal Power Act and PURPA as they relate to geothermal small power production facilities that are up to 80 MW in size. This rulemaking provides small power production facility status for geothermal facilities that are less than 50 percent owned by a utility. The size limitation does not apply to obtaining a PUHCA exemption, however.

FERC has intermittently revised its section 201 and 210 regulations to reflect changes in policy and the law. The most recent substantial change is the result of section 201(m), which was added as the result of the enactment of section 1253 of the Energy Policy Act of 2005. This resulted in several major changes, which include changes in ownership restrictions in defining what is a QF, changes due to modifications of affiliate transaction rules due to potential interaction subsequent to PUHCA repeal, and a change in the technology requirement for cogeneration QFs. The EAct 2005 amendments also resulted in the opt-out provisions, which will be described in further detail in the next section.

Prior to the passage of EAct 2005, no more than 50 percent of a QF could be owned by an electric utility. Section 1253(b) eliminated this ownership requirement. Because EAct 2005 also repealed the Public Utility Holding Company Act of 1935, FERC also eliminated the QF exemption from that statute; however, provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005) continued to apply to QFs unless they qualify for an exemption. Those qualifying for an exemption from PUHCA 2005 include cogeneration QFs of any size, small power production QFs of 30 MW or smaller, geothermal and biomass small power production QFs of any size, and certain small power production facilities QFs of any size designated as “eligible” under section 3(17)(E) of the Federal Power Act.

A cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than producing both forms of energy separately. For example, in addition to producing electricity, large cogeneration facilities might provide steam for industrial uses in facilities such as paper mills, refineries, or factories, or for heating, ventilating and air conditioning applications in commercial or residential buildings. Smaller cogeneration facilities might provide hot water for domestic uses or other applications. EAct 2005 1253 also added a new subsection (n) to PURPA section 210. Section 210 (n) establishes criteria regarding thermal output, use of electrical output, and the use of advanced technologies that all new cogeneration QFs must achieve in order to obtain QF status. In particular, the following criteria for new cogeneration QFs apply for 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 FERC certification as a qualifying cogeneration facility under § 292.207 prior to February 2, 2006, and which is seeking to sell electric energy pursuant to PURPA section 210.

First, the additional criteria for new cogeneration QFs require that an applicant demonstrate that it meets two criteria: (1) that the thermal energy output of the cogeneration facility is used in a productive and beneficial manner; and, (2), 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. This item takes 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. As for the first item, where a thermal host existed prior to the development of a new cogeneration facility whose thermal output will supplant the previous thermal source, the new cogeneration facility’s thermal output is assumed to satisfy the requirement.

A second test for a new cogeneration QF is the “fundamental use” test. For the purpose of satisfying the second criterion, the electrical, thermal, chemical and mechanical output of the cogeneration facility is considered to be 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 annual aggregate output 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 FERC that the facilities nevertheless should be certified given state laws applicable to sales of electric energy or unique technological, efficiency, economic, and variable thermal energy requirements.

In terms of a new cogeneration facility of 5 MW or smaller, those will be presumed to satisfy the requirements both criteria. There is no size limitation for new or existing qualifying cogeneration facilities.

## II Detailed Summary of PURPA Regulations and Discussions

This section is a detailed summary of the federal regulations (Code of Federal Regulations – or CFR) implementing PURPA. The full section of the CFR that pertains to PURPA (§292) is provided in Appendix A to this manual. What follows is a rearrangement of the CFR subsections by topic, and, where necessary, restated for simplicity. Also, more detailed explanations are provided for context on the more essential topics (this text is identified by a shaded background in this section).

### § 292.101(1)

(i) **A qualifying facility may also 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.

## FERC Regulation Subparts A and B: Definitions and Criteria for Qualification

### Definition of Qualifying Facility and Cogeneration Facility (§292.101)

The term “Qualifying Facility” (QF) is defined under Section (§) 292 of the CFR as “a cogeneration facility or a small power production facility that is a qualifying facility under Subpart B” (explained below).

**A cogeneration facility** is defined in §292.202(c) as “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.” There are two general types of cogeneration facility defined. The first is referred to in §292.202(d) 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. The second is referred to in §292.202(e) 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.

### Criteria for qualifying cogeneration facilities (§292.205)

#### *§292.205 (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.

<b>Cogeneration terms defined by FERC rule (as lettered in rule)</b>	<b>Definition</b>
<b>(f) Supplementary firing</b>	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.
<b>(g) Useful power output of a cogeneration facility</b>	Electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.
<b>(h) Useful thermal energy output of a topping-cycle cogeneration facility</b>	The thermal energy is (1) made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water); (2) used in a heating application (e.g., space heating, domestic hot water heating); or (3) used in a space cooling application (i.e., thermal energy used by an absorption chiller).
<b>(i) Total energy output of a topping-cycle cogeneration facility</b>	Defined as the sum of the useful power output and useful thermal energy output.
<b>(j) Total energy input</b>	The total energy of all forms supplied from external sources
<b>(k) Natural gas</b>	Defines as either natural gas unmixed, or any mixture of natural gas and artificial gas.
<b>(l) Oil</b>	Defined as crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products; and
<b>(m) Energy input of energy in the form of natural gas or oil</b>	Measured by the lower heating value of the natural gas or oil.
<b>(s) Sequential use of energy</b>	For a topping-cycle cogeneration facility, the use of rejected heat from a power production process in sufficient amounts in a thermal application or process to conform to the requirements of the operating standard. For a bottoming-cycle cogeneration facility, the use of rejected heat from a thermal application or process, at least some of which is then used for power production.



(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.

**§ 292.203(b) 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 FERC a notice of self-certification, pursuant to § 292.207(a); or has filed with the FERC an application for Commission certification, pursuant to § 292.207(b)(1), that has been granted.

**§292.203(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 FERC 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.

**§292.205(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.

#### ***§292.205(c) Waiver***

The FERC 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.

#### ***§292.205(d) Criteria for new cogeneration facilities***

Notwithstanding paragraphs (a) and (b), any cogeneration facility that either was 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 prior to February 2, 2006, and which is seeking to sell electric energy pursuant to PURPA section 210, 16 U.S.C. 824a-1, must also show:

- (1) That the thermal energy output of the cogeneration facility is used in a productive and beneficial manner; and
- (2) 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, 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) 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 to be 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 their 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), 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), where a thermal host existed prior to the development of a new cogeneration facility whose thermal output will supplant the previous thermal source, the thermal output of the new cogeneration facility will be presumed to satisfy the requirements of paragraph (d)(1).

## Requirements for small power production facility qualification (§292.203)

### *(a) General small power production facility qualification*

A small power production (SPP) facility is a QF (except hydroelectric small power production facilities, as explained in a separate section, below) 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 FERC a notice of self-certification, pursuant to § 292.207(a); or has filed with the FERC an application for Commission certification, pursuant to § 292.207(b)(1), that has been granted.

## Criteria for qualifying small power production facilities (§292.204)

### *(a) The maximum size of a SPP facility*

- (1) Except as provided in paragraph (a)(4), 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**.
- (2) 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 (§ 292.204(a)(2)(i)). The distance between facilities is measured from the electrical generating equipment of a facility (§ 292.204(a)(2)(ii)).
- (3) Waiver. The FERC 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 the facilities are not considered when determining the maximum size of other small power production facilities that are within one mile of 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, 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 is considered biomass.

## **Biomass provisions (§292.202)**

(a) Biomass means any organic material not derived from fossil fuels;

(b) Waste means an energy input listed below, 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

(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 after the year when the facility first produces electric energy.

<b>Terms that may apply to all Qualifying Facilities</b>	<b>Definition in FERC rule</b>
<b>Purchase</b>	Refers to the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.
<b>Sale</b>	Refers to the sale of electric energy or capacity or both by an electric utility to a qualifying facility.
<b>System emergency</b>	Defined 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.
<b>Rate</b>	Defined as 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.
<b>Avoided costs</b>	Refers to 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, the utility would generate itself or purchase from another source.
<b>Interconnection costs</b>	Defined as 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. These are recognized to the extent the 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 calculating avoided costs.
<b>Supplementary power</b>	Refers to electric energy or capacity supplied by an electric utility that is regularly used by a qualifying facility in addition to that which the facility generates itself.
<b>Back-up power</b>	This 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.
<b>Interruptible power</b>	Refers to electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.
<b>Maintenance power</b>	Defined as electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

## Why Become a QF?

Qualifying facilities may enjoy benefits under federal, state, and local laws. The benefits conferred upon QFs by federal law include (1) the right to sell energy and/or capacity to its host utility, (2) the right to purchase certain services from utilities, and (3) relief from certain regulatory burdens. Each of these set of benefits was modified by EPAct 2005. In addition, each QF has the right to interconnect with its host utility by paying a nondiscriminatory interconnection fee approved by the state commission or nonregulated utility. The interconnection must be done in accordance with applicable state law and/or applicable Open Access Transmission Tariff (OATT). How the obligation to interconnect works will be further discussed in [Interconnection Rules with Host Utilities and the Problem of Queuing](#).

Under 18 CFR sec. 304, QFs have the right to sell energy and capacity to its host utility, provided, however, the purchasing utility has not been relieved of its QF purchase obligations pursuant to EPAct 2005. (See 18 CFR sec. 309 – 311.) With that exception, QFs generally have the option of selling to a utility either at the utility's avoided cost or at a negotiated rate. QFs also generally have the option to sell energy either as-available or as part of a legally enforceable obligation for delivery of energy and/or capacity over a specified term. EPAct 2005 provides for a utility to opt out of certain new and expiring host utility mandatory obligations to purchase power, provided that the QF has nondiscriminatory access to one of three categories of markets. These opting-out provisions are discussed in further detail in [EPAct 2005 – Opt-Out Provisions in Competitive Markets](#).

So long as a selling utility has not been relieved of its duty pursuant to EPAct 2005, QFs have the right to purchase supplemental, back-up, maintenance, and interruptible power at rates which are just and reasonable, based on accurate data and consistent system-wide costing prices on a non-discriminatory basis. In other words, they can purchase power on the same basis that apply to the utility's other customers with similar load or cost-related characteristics. See CFR sec. 292.305.

QFs receive relief from several regulatory burdens. Recall that part of EPAct 2005 resulted in the repeal of the Public Utility Holding Company Act of 1935, which was replaced by the Public Utility Holding Company Act of 2005. That means the following categories of QFs are now exempt from the Public Utility Holding Company Act of 2005: cogeneration QFs of any size, small power production QFs of 30 MW or smaller, geothermal and biomass small power production facilities of any size, and certain small power production facilities of any size that are designated as "eligible under section 3(17)(E) of the Federal Power Act. Such an "eligible" solar, wind, waste or geothermal facility is defined as meaning a facility which produces electric energy solely by the use, as a primary energy source, of solar energy, wind energy, waste resources or geothermal resources. This was constrained by an entity submitting to FERC no later than December 31, 1994 either an application for certification of the facility as a qualifying small power production facility, or notice that the facility meets the requirements for qualification. If the latter is chosen, then construction of the facility needed to commence no later than December 31, 1999, or, if not, then reasonable diligence must be exercised toward completing the facility taking into account all factors relevant to its construction.

These same categories of QFs are exempt from state laws and regulations respecting the rates and financial and organizational aspects of utilities. They also are largely exempt from most provisions (except for those of section 205 and 206) of the Federal Power Act. Sections 205 and 206 provide FERC with authority to regulate the rates that FERC-jurisdictional entities charge for transmission and the sale of wholesale electric energy. In addition, energy and capacity sales made by the following categories of QFs are exempt from FERC scrutiny under FPA sections 205 and 206: QFs 20 MW in size or smaller, QFs making sales pursuant to a contract executed on or before March 17, 2006, and, QFs making sales pursuant to a state commission's implementation of PURPA section 210.

## **Procedures for obtaining qualifying status (§ 292.207)**

### ***(a) Self-certification***

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, and complying with paragraph (c).

### ***(b) Optional procedure***

(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 FERC an application for Commission certification that the facility is a qualifying facility. The application must be accompanied by the fee prescribed in part 381 of the chapter, and the applicant for Commission certification must comply with paragraph (c).

(2) General contents of application. The application must include a properly completed Form No. 556 pursuant to § 131.80 of this chapter.

(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 issuing an order [that is, pause or delay of the running of the period of time for issuing an order]. Any order denying certification must 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 is 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) Notice requirements*

(1) An applicant filing a self-certification, self-recertification, application for FERC certification or application for FERC recertification of the qualifying status of its facility must concurrently serve 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. FERC will publish a notice in the Federal Register for each application for FERC certification and for each self-certification of a cogeneration facility that is subject to the requirements of § 292.205(d).

(2) For facilities with a net power production capacity of 500 kW or more, an electric utility is not required to purchase electric energy until 90 days after the facility notifies the facility [sic, this should read "facility notifies the utility," based on the language in FERC Order 732 at para. 77] that it is a qualifying facility or 90 days after the utility meets the notice requirements in paragraph (c)(1) of this section.

*(d) 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 FERC, 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 FERC 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 FERC 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 FERC 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.

***§292.202 (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 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.



## Determining Avoided Cost

Perhaps the most challenging implementation issue for states and non-regulated utilities over the decades since PURPA was passed has been the determination of avoided cost. FERC defined avoided cost as “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.” This definition may seem simple and straightforward, but, in practice, avoided cost arguably has been the most difficult component of PURPA to settle.

Section 210 of PURPA states that rates for purchase by electric utilities must be “just and reasonable to the electric consumers of the electric utility and in the public interest. They also may not discriminate against qualifying cogenerators or qualifying small power producers. And, the FERC rule cannot “provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy” (sec. 210 (b)). PURPA then defines “incremental cost of alternative electric energy” 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” (sec. 210 (d)).<sup>5</sup> In the congressional 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 under this section [subsection (b)] to purchase electric energy.”<sup>6</sup> Conferees also note that they did not intend to have cogenerators or small power producers subject, under the commission’s [FERC’s] rules, to “utility-type regulation.”<sup>7</sup>

In Order 69, FERC breaks avoided costs down into its two components, costs which an electric utility can avoid by making such purchases generally can be classified as “energy” cost 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.

FERC further defined costs in Order 69 by noting that if a utility purchases energy from a QF that would reduce its energy cost or would avoid purchasing energy from another utility, the rate for purchase from the QF should be based on the energy cost that the utility avoided. Also, 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 rate for such a purchase will be based on the avoided capacity and energy costs” (FERC Order 69, 45 Fed. Reg. 12214, 12226, February 25, 1980).

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<sup>5</sup> PURPA does not contain the words “avoided costs” in the text; the term was created by FERC rulemaking.

<sup>6</sup> Conference Report to accompany H.R. 4018, Oct. 6, 1978, page 98.

<sup>7</sup> Id.

FERC states that “avoided incremental costs (and not average system costs) should be used to calculate avoided costs” (FERC Order 69, at 12216). Also, “if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used” (FERC Order 69, at 12216).

FERC offers an example of how this may be determined: “[o]ne way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility’s net avoided cost” (FERC Order 69, at 12216).

FERC allows that agreements between a utility and a QF for purchase rates different than rates required by the rules, or “under terms or conditions different from those set forth in these rules,” does not violate the rules under section 210 of PURPA.

FERC outlined “factors affecting rates for purchase” that remains part of the current rule (sec. 292.304 (e)). Summarized from the rule (the rule text is listed below), these factors to be considered when determining purchase rates include,

- ability of the utility to dispatch the QF,
- expected or demonstrated reliability of the QF,
- the terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance,
- the extent to which scheduled outages of the QF can be usefully coordinated with scheduled outages of the utility's facilities,
- the usefulness of energy and capacity supplied from a QF during system emergencies, including its ability to separate its load from its generation,
- the individual and aggregate value of energy and capacity from QFs on the electric utility's system; and
- the smaller capacity increments and the shorter lead times available with additions of capacity from QFs

In addition, FERC noted two other considerations, the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use, and 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.

There are several methods that have been used by states for long-term contracts to establish avoided costs. These methods have generally satisfied FERC requirements and have been in use for many years. They are listed here with a brief description.<sup>8</sup>

### **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.<sup>9</sup> The type and size of the unit or units is determined in an Integrated Resource Process (IRP) or from the utility's planning process, where the planning process, for regulated utilities, follows a state commission-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.<sup>10</sup>

### **"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 (CT).<sup>11</sup> 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.<sup>12</sup>

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<sup>8</sup> Two discussion of these methods can be found in Graves, Hanser, and Basheda, "PURPA: Making the Sequel Better than the Original," Edison Electric Institute, December 2006, posted at: <http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/purpa.pdf>; and Carolyn Elefant, "Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies In Supporting Alternative Energy Development and a Proposed Path for Reform," undated manuscript, posted at: <http://www.recycled-energy.com/images/uploads/Reviving-PURPA.pdf>.

<sup>9</sup> Graves, Hanser, and Basheda, *ibid.* p. 9.

<sup>10</sup> Elefant, *Op. cit.* p. 17.

<sup>11</sup> Graves, Hanser, and Basheda, *Op. cit.* p. 10.

<sup>12</sup> Graves, Hanser, and Basheda, *Op. cit.* p. 11.

### 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.

### Auction/RFP rates

Auctions, or bidding, programs were used by several states beginning in the late 1980s. If a utility required capacity, the utility would issue an RFP specifying the type of capacity needed and the selection criteria. Winning projects were selected according to price and other explicit factors. These factors were similar to “factors affecting rates for purchase” that FERC outlined and are listed above. Successful bidders receive capacity contracts; unsuccessful QF bidders may sell energy at avoided energy costs as required under PURPA, but not receive a capacity payment.<sup>13</sup>

These programs varied from state to state on how involved the commission was in the design and application of the bidding program. Some states had highly prescriptive evaluation criteria and qualification of the bidders that utilities were required to follow, while other states gave the utility a great deal of discretion. In some cases the utility was allowed to participate in process as a bidder.

### Net Metering

Net metering has been widely used by state commissions and non-regulated utilities as a convenient means to compensate small renewable QF facilities. Unless limited solely to netting unbundled energy costs, net metering is not a way of calculating avoided cost. FERC has deemed that under net metering no mandatory purchase or sale of electricity is taking place under PURPA and its avoided cost regulations so long as a retail customer with on-site generation is not a net supplier of energy to the grid over the state retail billing period, which is usually monthly. Under this interpretation, the full avoided cost cap on purchases of QF power does not apply, because no purchase took place. [See *Midwestern Energy Co.*, 94 FERC para. 61,340 (2001); and *Sun Edison LLC*, 129 FERC para. 61,146 (2009).]

Minnesota passed the first net metering law in 1983, providing net metering for renewables up to 40 kW. Prior to that, utilities in Idaho had adopted net metering in 1980, and in Arizona in 1981. Massachusetts adopted net metering in 1982. By 1998, 22 states or utilities had adopted net metering. Originally, net metering allowed small energy producers (typically small renewable energy producers) to sell electricity to their host utility at the retail rate. Section 1251 of EPCA 2005 required states (under a PURPA section 111 consideration and determination) to decide whether or not to implement net metering upon request by electric customers with eligible on-site generation. As of 2013, 43 states had adopted net metering, as well as utilities in several of the remaining seven states. Only three states were without any established procedures: Mississippi, Tennessee, and South Dakota.

Procedures and qualifications for net-back billing vary widely from state to state. There are limits on the size of the facility eligible for net-back billing in most states. Those qualifications can be as low as 10 kW, which is in place in several states, to as high as 80 MW (that is, 80,000 kW) in New Mexico. Many

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<sup>13</sup> Rose, Burns, and Eifert, “Implementing A Competitive Bidding Program For Electric Power Supply,” The National Regulatory Research Institute,” January 1991; <http://www.ipu.msu.edu/library/pdfs/nrri/Rose-Burns-Eifert-Competitive-Bidding-90-15-Jan-91.pdf>.

states also have subscriber limits that cap the percentage of load that can subscribe to net metering. Idaho limits their subscribers to 0.1 percent of a utility's peak demand in 1996.<sup>14</sup> 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. And, policies vary as to whether there are monthly rollover of credits, as well as whether there is annual compensation, and, if so, how it is calculated.<sup>15</sup>

Net billing of more the unbundled energy costs provides the behind-the-meter generator (BTMG) with more than the avoided energy costs that an “as-available” QF might receive. Under the most typical net billing (there are a few exceptions) scenario, the BTMG also nets out its distribution, transmission, and other customer costs, which are not avoided. Some contend that this either creates a cross-subsidy that flows from those customers without BTMG to customers with BTMG, and that that is discriminatory; or is unconstitutional confiscation because the utility would not have an opportunity to recover its prudently incurred expenditures on transmission and distribution.<sup>16</sup> These issues are also being raised in other states.

## Renewable Energy Credits/ Certificates (RECs)

Renewable Energy Credits or Renewable Energy Certificates (RECs), which sometimes also go by names such as green tags and tradable renewable certificates are tradable, non-tangible energy commodities that represent proof that 1 megawatt-hour (1 MWh) of electricity was generated from an eligible renewable energy resource. In states with a REC program, an eligible generator is issued one REC for every 1,000 kWh it produces. Eligible generation technologies for RECs, while not standard nationwide, include many small power energy power producers (typically without a size limitation), including those from solar PV, solar thermal power, wind energy, geothermal, small hydroelectric, biomass, biofuel, and landfill gas. In a few states, power from combined heat and power--that is, cogeneration facilities--also qualifies. In *American Ref-Fuel Co.*, 105 FERC para. 61,004 (Oct. 1, 2003), FERC determined that contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility unless the contract states otherwise. The avoided cost regulations did not contemplate the existence of RECs, and the environmental attributes of the QF were not a factor in the avoided cost rates, which were intended to compensate the QF for capacity and energy. FERC also held

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<sup>14</sup> From Database of State Incentives for Renewables and Efficiency (DSIRE), <http://www.dsireusa.org/>.

<sup>15</sup> For more detailed state-by-state information on net metering, see <http://www.dsireusa.org/summarytables/rrpre.cfm> and [http://en.wikipedia.org/wiki/Net\\_metering](http://en.wikipedia.org/wiki/Net_metering).

<sup>16</sup> See for example, David B. Raskin, The Regulatory Challenge of Distributed Generation, 4 Harv. Bus. L. Rev. Online 38 (2013), <http://www.hblr.org/?p=3673>. Recently the Arizona Corporation Commission issued a decision that set fee that net metering customers would pay as a way of addressing these issues. In the Matter of Arizona Public Service Company's Application for Approval of Net Metering Cost Shift Solution, Arizona Corporation Commission, Order, Decision 74202, Docket E-01345A-13-0248 (December 8, 2013). <http://images.edocket.azcc.gov/docketpdf/0000149849.pdf>.

that while a state may decide that sale of power at wholesale automatically transfers ownership of the state-created REC, that requirement must find its authority in state law, not PURPA.

Although RECs do not fall under PURPA regulations, dealing with RECs can be bound up with the negotiated contracts. Also, state law can assign RECs to one party or another. RECs are also of great concern because they are needed to fulfill state renewable portfolio standards. As of March 2013, according to the Database of State Incentives for Renewables & Efficiency, 29 states and the District of Columbia have Renewable Portfolio Standard Policies, and eight additional states have renewable portfolio goals. The standards vary widely as to the timing of meeting the renewable portfolio standard, the level of the ultimate goal, and whether there are minimum solar or customer-sited requirements or incentives. (In some states non-renewable alternatives--cogeneration, for example, or fossil-fuel generation with carbon capture--would count.<sup>17</sup>) Fulfilling the RPS requirements gives value to RECs, and markets have developed to trade RECs. These regional markets often have unique numbering systems to make certain that RECs are not sold multiple times. When the REC is sold separately and used by a party other than the purchasing utility, the consumer of the REC receives a certificate, which, if it complies with the state RPS, contributes to fulfilling that entity's RPS requirement.

Purchase and/or sale of a renewable energy certificate might be done according to a model agreement, entitled a "Master Renewable Energy Certificate and Purchase and Sale Agreement," which was prepared by an ad hoc working group of members of the American Bar Association's Section on Environment, Energy, and Resources, the Environmental Markets Association, and the American Council on Renewable Energy to facilitate orderly trading in and development of a standard green tag.<sup>18</sup>

Alternatively, the Edison Electric Institute (EEI) facilitated an industrywide collaboration with the National Energy Marketers Association and others to develop a model bilateral master agreement. This document contains the essential terms governing forward purchases and sales of wholesale electricity. The Master Contract streamlines establishing a trading relationship, provides real-time credit provisions, standardizes product definitions, and focuses traders on the transaction's basic negotiable elements, for example, price, quantity, location, and duration. The EEI Renewable Energy Certificates (RECs) Annex to the Master Agreement is designed to enable REC trading between EEI counterparties. The Annex has been streamlined to remove certain features that market developments have not required, while other features have been added or enhanced in order to maximize utility for potential users.<sup>19</sup>

While the U.S. currently does not have a national registry of RECs issued, the Center for Resource Solutions (CRS) administers a voluntary program which attempts to ensure RECs are properly accounted for and that no double counting takes place.<sup>20</sup> Under the Green-e Energy program, participants are required to submit to an annual Verification Process Audit of all eligible transactions to ensure the RECs

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<sup>17</sup> See [http://www.dsireusa.org/documents/summarymaps/RPS\\_map.pdf](http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf).

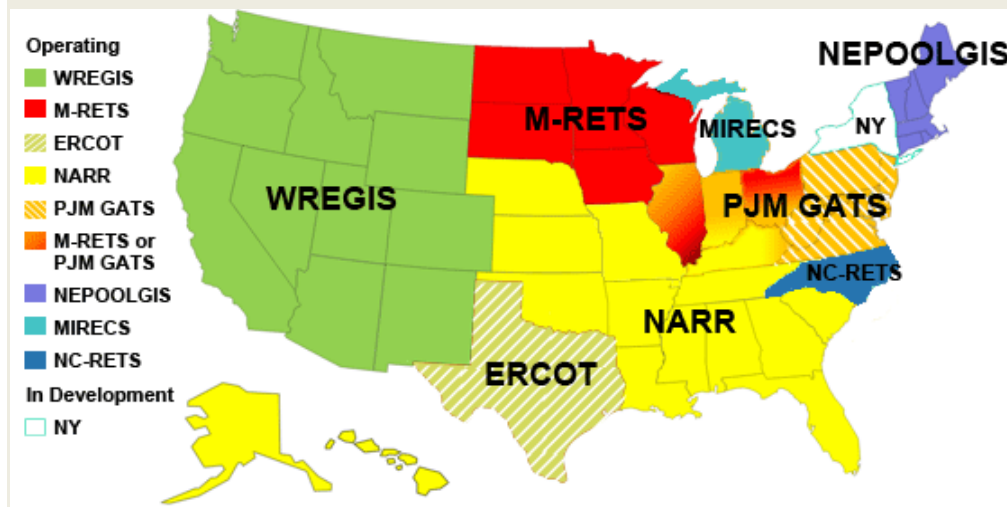
<sup>18</sup> See <http://apps.americanbar.org/environ/committees/renewableenergy/RECMasterContract.pdf>.

<sup>19</sup> <http://www.eei.org/resourcesandmedia/mastercontract/Documents/EEI%20RECs%20Annex%20v1.pdf>.

<sup>20</sup> See [http://www.resource-solutions.org/pub\\_pdfs/RECs&OffsetsQ&A.pdf](http://www.resource-solutions.org/pub_pdfs/RECs&OffsetsQ&A.pdf).

meet the requirements for certification. The certification process requires third-party verification by an independent certified public account or a certified internal auditor. CRS maintains a list of auditors who meet the criteria to be listed on the program website.

It is important that the REC comply with the applicable tracking system. Increasingly, RECs are being assigned unique identification numbers and tracked through regional tracking systems/registries such as [WREGIS](#), [NEPOOL](#), [GATS](#), [ERCOT](#), NARR, MIRECS, NRTEC, NC-RETS and [M-RETS](#).<sup>21</sup>



Regional tracking systems that have been developed in the United States.

**Figure 1. Certificate Tracking Systems**

REC tracking map courtesy of Ed Holt & Associates, Inc. Note: Tracking systems are geographically approximate and do not precisely coincide with state boundaries. Also, sites linked from this map are not on the Environmental Protection Agency web site and some are linked to external files. [Please see our disclaimer information.](#)

**EXIT Disclaimer** Some tracking systems will also issue certificates for generation located in Canadian provinces and Mexican states.

## Feed-in Tariffs

Other than avoided cost rates reached by negotiated contract and avoided cost rates that at the time they were determined did not exceed the utility's full avoided costs, standard-offer avoided cost rates cannot exceed avoided cost. Externalities and environmental adders, although uncommon, are permitted to be included in the calculation of avoided costs, so long as the costs avoided are not speculative but reflect, for example, the cost of avoiding purchase of emission allowances or other costs associated with externalities.<sup>22</sup>

<sup>21</sup> See <http://www.epa.gov/greenpower/gpmarket/tracking.htm>.

<sup>22</sup> See for example, Biennial Determination of Avoided Cost Rates, Docket E-100, NCUC, 2007 NC PUC LEXIS 1786 (Dec. 2007).



Until recently, avoided cost determined via a market auction could not be based on an all-source auction. FERC specifically prohibited avoided cost rates based on QF-only bid processes.<sup>23</sup> However, in FERC's 2010 Order Granting Clarification and Dismissing Rehearing for *California Public Utilities Commission*, 133 FERC para. 61,059 (October 21, 2010), the Commission clarified that when determining avoided cost rates, the California PUC could excluded resources that did not satisfy state law procurement requirements (for example, high carbon emitting resources). The California Commission need not consider such sources, since they are not eligible to sell to California utilities. And, on the issue of whether the California Commission could include a pricing adder for CHP (cogeneration) facilities sited in such a way that they will cause the utility to avoid or postpone transmission upgrades, FERC indicated that the California Commission may take into account actual state procurement requirements, and the resulting costs, imposed on California utilities. Thus, FERC Order on Clarification distinguished and effectively overruled the all-source requirement of the *Southern California Edison* case.

Current law continues to provide that utilities are not required to pay more than the full avoided cost of purchased QF power. These avoided costs, however, may include actual, non-power costs, and need not consider alternative sources that are not eligible under a state's procurement rules.

The issue becomes, then, one of how broadly can the Clarification Order be read? The Clarification Order provides states with the flexibility to exclude potential resources for the calculation of avoided costs provided those resources are excluded from the states procurement requirements. Under one interpretation, the Clarification Order could provide state commissions with new flexibility to use PURPA to have utilities pay resource-differentiated or resource-specific avoided cost rates. The Clarification Order supports avoided costs being determined according to all sources being able to sell to the utility. If a state procurement program limits sources that cannot sell, they are not to be included in the avoided cost calculation.

The Clarification Order also states that FERC finds that the concept of multi-tiered avoided cost rate structures can be consistent with the avoided cost rate requirements of PURPA and FERC regulations. The question in this case becomes one of determining what costs the electric utility is avoiding. Under FERC regulations, a state may determine that capacity is being avoided and so may rely on the cost of such avoided capacity to determine the avoided cost rate. A state may take into account obligations state that, for example, utilities purchase energy from particular sources of energy or for a long duration. FERC provided an example: "if a state required a utility to purchase 10 percent of its energy needs from renewable resources, then a natural gas-fired unit, for example, would not be a source 'able to sell' to that utility for the specific renewable resources segment of the utility's energy needs, and thus would not be relevant to determining avoided costs for that segment of the utility's energy needs. ... [W]here a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement section."<sup>24</sup> In other words, a state may

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<sup>23</sup> See *Southern California Edison*, 70 FERC para. 61,215 (1995), *aff'd* rehearing, 71 FERC para. 61,090 (1995).

<sup>24</sup> *Id.*, at n. 53.



appropriately recognize procurement segmentation by making separate avoided cost calculations. Nevertheless, the QF rate must not exceed the applicable avoided cost of the utility.

On May 24, 2012, the California PUC adopted an Administrative Law Judge's decision implementing a disturbed generation Feed-in-Tariff (FIT) as required by California's legislature.<sup>25</sup> The FIT fulfills a state law requiring utilities to purchase 750 MW from eligible renewable generators that are 3 MW or less in size and sited at strategic locations on the electric utility distribution system. The California PUC opted not to use a gas-based Market Price Referent, but, instead, to base the price on the market price of renewables. FIT uses a Renewable Auction Mechanism (RAM) to determine a starting price, based on the weighted average of Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric's highest executed contract resulting from the RAM auction held November 2011 for the FIT. It then adjusts that starting price from the Renewable Market Adjusting Tariff (Re-Mat) according to the duration of the contract (10-, 15-, 20-year terms) and whether the generation is baseload, peaking as-available, or non-peaking as-available. QFs eligible for the FIT program are not eligible for the RAM program. In other words, smaller renewable projects (3 MW or less) fall under FIT and may not participate in the Renewable Auction Mechanism. Participation in the FIT program is capped by statute at 750 MW.

As discussed further in Part III of this Manual, on June 13, 2013, Winding Creek Solar petitioned FERC for an enforcement action against the California Commission to remedy orders that Winding Creek contends improperly implemented PURPA through California's feed-in tariff (FIT) program. Winding Creek's contention is that the FIT is based on an incorrect PURPA interpretation because it violates PURPA and FERC regulations. Specifically, Winding Creek argued that the FIT fixes the wholesale price for the power purchased from a QF at a price that was not determined to be the utility's full long-term avoided cost, the FIT eliminates a small QF's ability to seek an avoided cost long-run rate except through the FIT/Re-MAT Program, and outside of the Re-Mat program, new smaller QFs are only entitled to a short-run rate. FERC's action and the state of the case, as of this writing, is further discussed in Part III.

Regardless of the ultimate outcome of this case, it would appear not to be determinative as to the issue of whether states can require specific resource-differentiated avoided costs that are tied to achieving renewable portfolio standards. Strictly speaking, these would not be feed-in-tariffs as the term is used internationally, but, rather, would be tied to determining the purchasing utility's cost of meeting resource procurement requirements in a renewable portfolio standard. It further raises the issue as to what degree RECs may fulfill a state's RPS and if they can be a means of determining a utility's avoided cost in meeting its RPS requirements.

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<sup>25</sup> See California PUC Decision 12-05-035.

## **FERC Regulation Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978 (§ 292.301)**

Subpart C applies to the regulation of sales and purchases between qualifying facilities and electric utilities. 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.

### **Availability of electric utility system cost data (§ 292.302)**

This subsection applies to each electric utility, in any calendar year, if the total sales of electric energy for purposes other than resale exceeded 500 million kilowatt-hours.

Regulated and non-regulated electric utilities that meet this threshold must make available data from which avoided costs can be derived, at least every two years (and in the case of regulated utilities, provide it to its state regulatory authority); and 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. The levels of purchases must be stated in blocks of not more than 100 MW for systems with peak demand of 1,000 MW or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1,000 MW. The avoided costs must 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 for 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 must be expressed in terms of individual generating units and individual planned firm purchases.

### *Substitution of alternative method*

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 non-regulated 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. A state regulatory authority or non-regulated utility which requires different data must notify FERC within 30 days of making such a determination.

### *State Review*

Any data submitted by an electric utility under this section is subject to review by the state regulatory authority, which has ratemaking authority over the electric utility. In any review, the electric utility has the burden of coming forward with justification for its data.

## **Electric utility obligations under this subpart (§ 292.303)**

### *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 the next paragraph on transmission to other electric utilities.

### *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 the electric utility. The rate for purchase by the electric utility to which such energy is transmitted may be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4), but may not include any charges for transmission.

### *Special rule for small electric utilities that do not meet the threshold limit § 292.302(c)*

upon request, can (i) provide comparable data to that required in § 292.302 above to enable qualifying facilities to estimate the electric utility's avoided costs; 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 that energy and capacity. If any (small) 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 to FERC for an order requiring that the information be provided.

### ***Obligation to sell to qualifying facilities***

Each electric utility must sell to any qualifying facility, in accordance with § 292.305, unless exempted by § 292.312, energy and capacity requested by the qualifying facility.

### ***Obligation to interconnect***

Electric utilities must incur interconnection costs with any qualifying facility necessary to accomplish purchases or sales under this subpart. The obligation to pay for interconnection is determined in accordance with § 292.306. However, 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.

### ***Parallel operation***

Each electric utility must 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.

### ***Rates for purchases (§ 292.304)***

(a) Rates for purchases are to be:

- (i) 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.

Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

### ***(c) Standard rates for purchases***

Each electric utility is required to have standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. There may be standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts. The standard rates for purchases under this paragraph:

***(b) Relationship to avoided costs***

For purposes of “Rates for Purchase” (§ 292.304) paragraph:

“New capacity” means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

Subject to the next paragraph, a rate for purchases satisfies the requirements of (§ 292.304) if the rate equals the avoided costs determined after consideration of the factors set forth in “*Factors affecting rates for purchases*” paragraph.

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 non-regulated electric utility determines that a lower rate is consistent with this section, and is sufficient to encourage cogeneration and small power production.

Rates for purchases from new capacity shall be in accordance with this paragraph regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

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.

(i) shall be consistent with the opening paragraph of this subsection and the “Factors Affecting Rates for Purchases” paragraph outlined below; 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***

Each qualifying facility has the option to either:

(1) 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 purchasing utility's avoided costs calculated at the time of delivery; or

(2) 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, at the option of the qualifying facility exercised prior to the beginning of the specified term, 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.

***(e) Factors affecting rates for purchases***

In determining avoided costs, the following factors, to the extent practicable, are to be taken into account:

(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 QF 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 QF, 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 that authority determines necessary or appropriate, either before or after the occurrence.

## **Rates for sales (§ 292.305)**

### ***(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 system wide 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 FERC (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 FERC, 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.

## **Standby, Back-Up and Maintenance Power Issues**

Utilities have an obligation to sell power to a QF. The definition of the word “sell” is meant to include the sale of electric energy or capacity or both by an electric utility to a qualifying facility. So long as the electric utility continues to have an obligation to serve retail customers under state law, the electric utility has an obligation to sell any energy and capacity requested by the QF. (Under EPCRA 2005, if a utility no longer has an obligation to serve its retail customers under state law, it no longer has an obligation to sell power to QFs.) FERC regulations implementing PURPA specifically provide that utility sales to a QF are to be just and reasonable and in the public interest. Also, the rates charged may not discriminate against the QF in comparison with rates for sales to other utility customers. To fulfill this provision, the rates for sale are required to be based on accurate utility data and make use of consistent systemwide costing principles. Rates are considered to be nondiscriminatory to the extent that the rates charged to the QF also apply to other customers with similar load or other cost-related characteristics.

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. Supplementary power means electric energy or capacity supplied by an electric utility and regularly used by a QF in addition to that which the facility generates itself. 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. Interruptible power means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions. Maintenance power means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility. This obligation applies unless the state commission or unregulated utility, after notice and an opportunity to be heard, waives the requirement. The electric utility must demonstrate and the commission (or unregulated utility) must find that providing supplemental power, back-up power, maintenance power, and/or maintenance power would impair the



electric utility's ability to render adequate service to its customers or would place an undue burden upon the utility.

Rates for these services are to be based on systemwide costing principles and are to be non-discriminatory. There is an additional requirement, though, for calculating the rates for sales of back-up and maintenance power. (Sometimes, back-up and maintenance power together are referred to as "standby power.") 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. The rate will 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.

Recent reforms in FERC Orders 764 and 764-A intended to promote integration of Variable Energy Resources into the grid will further require 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 15-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), will be covered by these provisions. The data collected can have ramifications on systemwide costing of sales to a QF, particularly for supplemental, but also for back-up and maintenance power, as the data will 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.

## **Interconnection costs (§ 292.306)**

### ***(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 non-regulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

## Interconnection Rules with Host Utilities and the Problem of Queuing

QFs also have the right to interconnect with a utility by paying a nondiscriminatory interconnection fee approved by the state regulatory authority or a non-regulated electric utility.<sup>26</sup> Interconnection cannot be denied, however, reasonable and non-discriminatory terms and conditions can be required. Each QF is obliged to pay any interconnection cost which the state commission or non-regulated electric utility may assess against the QF on a nondiscriminatory basis with respect to other customers with similar load characteristics. Each state commission or non-regulated electric utility must determine the manner for payment of the interconnection costs, which may include reimbursement over a reasonable period of time.

Interconnection costs includes 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 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 that energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

It is worth noting that a QF can include not just the qualifying cogeneration or small power production facility. Under FERC regulations, a qualifying facility may include transmission lines and other equipment used for interconnection purposes (including transformers and switchyard equipment, see FERC Regulation Subparts A and B: Definitions and Criteria for Qualification), 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; (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*,<sup>27</sup> or (C) 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. The construction and ownership of such lines and equipment shall be subject to any applicable Federal, state, and local siting and environmental requirements. These provisions often come into play for QF wind energy farms and/or solar PV arrays.

On October 25, 2001, FERC initiated an Advance Notice of Proposed Rulemaking (ANOPR) aimed at Standardizing Generator Interconnection Agreements and Procedures (Docket RM02-1-000) applicable to interconnections that are subject to FERC jurisdiction. State commission representatives participating in the ANOPR process realized that this would be an opportune time for the states to develop model interconnection agreements and procedures for small generators to parallel the FERC process.

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<sup>26</sup> See 18 C.F.R. § 292.306.

<sup>27</sup> 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).

Several states -- California, Texas, New York, and Ohio -- had already completed distributed generation (DG) interconnection procedures and agreements for small generators after extensive stakeholder processes. With the support of the U.S. Department of Energy and under the direction of a Commissioner Steering Committee, the National Association of Regulatory Utility Commissioners (NARUC) established a Staff Working Group composed of state interconnection experts including attorneys, engineers, and other state staff. Although numerous states were represented in the Steering Committee and the Staff Working Group, the core of the working group consisted of state staff from the four states with approved DG procedures. Their experience with DG implementation facilitated preparation of the documents. These documents consist for the most part, of provisions that have been implemented by state commission orders and reflect the “best practices” of existing state procedures and agreements.

Over the years, NARUC has adopted a number of principles, policies, and resolutions recognizing the importance of DG, including small QFs, to the nation's energy systems. In an effort to harmonize state approaches to DG interconnection, NARUC passed a resolution in February of 2002 supporting the development of the two model documents for voluntary adoption or adaptation by the states: DG Interconnection Procedures for States, and DG Interconnection Agreement for States. The initial draft documents were presented at the NARUC Summer Meeting in 2002.<sup>28</sup>

In October 2003, NARUC subsequently approved and distributed:

[http://www.naruc.org/Publications/dgiaip\\_oct03.pdf](http://www.naruc.org/Publications/dgiaip_oct03.pdf). The document is available as a model interconnection procedure and agreement for distributed generators that sell solely to a host utility at retail, that is, QFs without wheeling power and without a wholesale sale of electricity, or DGs (whether or not QFs) interconnected solely at the distribution level.

In the meantime, FERC Order 2003 was issued on July 23, 2003, and provided standard interconnection procedures and a standard interconnection agreement for the interconnection of generators larger than 20 MW. The rule requires that public utilities that offer transmission services also offer non-discriminatory standardized interconnection service. Order 2003, however, also provided independent transmission entities, such as ISOs and RTOs, the opportunity to customize their interconnection procedures and agreements to meet regional needs. The generator must pay for the facilities on its side of the interconnection. The cost of interconnection facilities located at or beyond the point of interconnection would initially be paid by the generator, but would be regarded as network facilities to be repaid over time.

Further clarification of Order 2003 was provided in Orders 2003-A, -B, and -C.<sup>29</sup> Again, it is worth noting that, in many cases, RTOs and ISOs have filed their own interconnection procedures and

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<sup>28</sup> See Jan Karlack and Robert E. Burns, “Distributed Generation Model Procedures and Agreement.” Portland, Oregon, July 28, 2002.

<sup>29</sup> For the most updated version of FERC’s Large Interconnection Procedures, go to: <http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp>.

agreements with FERC. The applicable interconnection procedure and interconnection agreement are available at the appropriate RTO or ISO web site.

In June 2005, FERC issued Order 661, followed by Order 661-A in December 2005. The rule addressed interconnection requirements for wind power facilities larger than 20 MW. The rule requires transmission providers to append new provisions (Appendix G of Order 2003-A) to the standard agreement and procedures for interconnecting large generating facilities under Open Access Transmission Tariffs in order to address technical requirements and procedures for integrating large wind power facilities. The final rule provided that wind generators must meet any or all following conditions, if the transmission service provider demonstrates the conditions are needed. First, if needed, a large wind generating facility must remain operational during voltage disturbances on the grid. Second, if needed, large wind plants must meet the same technical criteria for providing reactive power to the grid as required of conventional large generating facilities. Third, if needed, supervisory control and data acquisition (SCADA) must be deployed to ensure real-time communications and data exchange between the wind power generator and the grid operator.<sup>30</sup>

On May 12, 2005 in Order 2006, FERC issued standard procedures and agreements for the interconnection of generators no larger than 20 MW. The rule applies to facilities that are already subject to FERC jurisdiction and specifically does not apply to DG (including QFs) interconnected to local distribution facilities, unless the distribution facility is subject to a transmission provider's pre-existing Open Access Transmission Tariff or involves a FERC jurisdictional wholesale sale. In the subsequent Order 2006-A, FERC further clarified that NARUC was correct in saying that a QF selling at retail is not eligible to interconnect under either Order No. 2003 or Order No. 2006. Under PURPA, such interconnections are governed by state law.

FERC further stated that while Order No. 2006 attempted to harmonize its provisions with existing state programs, it declined to formally recognize those programs in Order No. 2006. FERC stated that Order No. 2006 in no way affected rules adopted by the states for the interconnection of generators with state-jurisdictional facilities, and FERC said it expected that the vast majority of small generator interconnections would be with state jurisdictional facilities. It encouraged development of state interconnection programs, and interconnections with state jurisdictional facilities would continue to be governed by state law. However, if an interconnection customer were to seek to interconnect with a facility under federal jurisdiction, then a state program cannot displace federal rules for interconnections. Furthermore, FERC said it attempted to minimize the inconsistencies between federal and state interconnection rules by adopting many of the provisions suggested by NARUC and other state bodies, and by encouraging the states to consider using the streamlined small generator interconnection

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<sup>30</sup> Appendix G interconnection procedure and interconnection agreement language for large wind generators can be found at <http://www.ferc.gov/industries/electric/indus-act/gi/wind.asp>.

procedure (SGIP) and agreement (SGIA) for their own use. Order No. 2006 and 2006-A do not affect any existing interconnection agreements, whether they were entered into under state or federal law.<sup>31</sup>

On January 17, 2013, however, FERC issued a Notice of Proposed Rulemaking (NOPR) to revise the pro forma Small Generator SGIP and SGIA.<sup>32</sup> On November 22, 2013, FERC issued Order 792, which contains its Final Rule on these agreements and procedures. There are five amendments of particular note. First, provisions that provide an interconnection customer with the option of requesting from the transmission provider a pre-application report providing existing information about system conditions at the possible point of interconnection are incorporated. A utility, transmission owner, or RTO can recover the incremental cost of providing the information in the pre-application report. FERC determined that \$300 is the default fixed fee in the pro forma SGIP, although transmission providers may propose a different fee in their compliance filing if supported by a cost justification. This might include cost justifications for interconnection procedures previously found consistent with, or superior to, the pro forma SGIP and SGIA under the independent entity variation standard. Second, the pro forma SGIP was revised so that the 2 MW threshold for participation of synchronous and induction machines in the fast track process is included. The eligibility threshold for inverter-based machines will be 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 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. Third, supplemental review provisions for interconnection customers that fail to meet the fast track screens are provided (which include minimum load and other screens) to determine if a small generating facility may be interconnected safely and reliably. Fourth, the pro forma SGIP was revised to allow the interconnection customer an opportunity to provide written comments to the transmission provider on any upgrades required for interconnection. Fifth, the pro forma SGIP and SGIA were revised to specifically include energy storage devices.<sup>33</sup>

Recall that RTOs and ISOs are allowed flexibility to develop their own interconnection procedures and agreements for generators over 20 MW, and presumably also for smaller generators that are not subject solely to state jurisdiction. Typically, the market process of RTOs and ISOs involves transmission queues for interconnecting prospective generators, including QFs. On March 20, 2008, FERC issued an Order on interconnection queuing practices based on the findings from a technical conference.<sup>34</sup> FERC required RTOs and ISOs on or before April 21, 2008, to report about the size of their queues, the timeframes for processing requests, and problems with backlogs. The reports also were to explain the status of stakeholder discussion on queue reform and provide a schedule for necessary reforms, including a

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<sup>31</sup> For current small generator interconnection procedures and interconnection agreements for facilities under federal jurisdiction see: <http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp>.

<sup>32</sup> See FERC NOPR, Small Generator Interconnection Agreement and Procedure, 143 FERC para. 61,049, January 17, 2013.

<sup>33</sup> See FERC Order 792, Small Generator Interconnection Agreements and Procedures Final Rule, RM13-2-000, 146 FERC para.159, November 22, 2013.

<sup>34</sup> See 122 FERC Para. 61,252 (2008).

target date for filing tariff amendments or waivers in order to implement reforms. Queuing can still be a potential problem. Some proposed facilities, whether or not they are QFs, may lack economic viability if the transmission upgrades anticipated for projects earlier in queue do not come to fruition. In spite of recent reforms, queuing can jeopardize the development of otherwise viable QF and non-QF projects, and/or lead to anticipated generation being delayed or cancelled. The latter effect could potentially jeopardize regional supply adequacy and reliability. FERC said it hopes that regional transmission expansion planning will remedy this problem (most recently with Order 1000). Time will tell how successful that is, or what adjustments are necessary.

## **System emergencies (§ 292.307)**

### ***(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 that it is provided

- (1) for by agreement between facility QF and an electric utility, or it is
- (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 QF if such purchases would contribute to the emergency, and
- (2) sales to a qualifying facility, provided that the action is done on a nondiscriminatory basis.

## **Standards for operating reliability (§ 292.308)**

Any state regulatory authority (with respect to any electric utility over which it has ratemaking authority) or non-regulated 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.

## **Termination of obligation to purchase from qualifying facilities (§ 292.309)**

(a) After August 8, 2005, an electric utility shall not 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 if the FERC finds that the qualifying cogeneration facility or 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 § 292.309(a)(1), (2) and (3), 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. If the Commission determines that a market meets the criteria of § 292.309(a)(1), (2) or (3), 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.

(d)

(1) For purposes of § 292.309(a)(1), (2), and (3), there is a rebuttable presumption that a qualifying facility with a capacity at or below 20 MW does not have nondiscriminatory access to the market.

(2) For purposes of implementing paragraph (d)(1) of this section, the Commission will not be bound by the one-mile standard set forth in § 292.204(a)(2).

(e) Midwest Independent Transmission System Operator (Midwest ISO), PJM Interconnection, L.L.C. (PJM), ISO New England, Inc. (ISO-NE), and New York Independent System Operator (NYISO) qualify as markets described in § 292.309(a)(1)(i) and (ii), and there is a rebuttable presumption that qualifying facilities with a capacity greater than 20 MW have nondiscriminatory access to those markets through FERC-approved open access transmission tariffs and interconnection rules, and that electric utilities that are members of such regional transmission organizations or independent system operators (RTO/ISOs) should be relieved of the obligation to purchase electric energy from the qualifying facilities. A qualifying facility may seek to rebut this presumption by demonstrating, among other things, that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or



(2) 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.

(f) The Electric Reliability Council of Texas (ERCOT) qualifies as a market described in § 292.309(a)(3), and there is a rebuttable presumption that qualifying 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. A qualifying facility may seek to rebut this presumption by demonstrating, inter alia, that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or

(2) 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.

(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 FERC a notice of self-certification or self-recertification, or an application for FERC 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.

### **Procedures for utilities requesting termination of obligation to purchase from qualifying facilities (§ 292.310)**

(a) An electric utility may file an application with the FERC 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 FERC 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 FERC 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 FERC certification with the FERC 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 MW 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 Open Access Same-Time Information System (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 FERC 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.

### **Reinstatement of obligation to purchase (§ 292.311)**

At any time after the FERC 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 FERC for an order reinstating the electric utility's obligation to purchase electric energy under this section. The application must 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 FERC must issue an order within 90 days reinstating the electric utility's obligation to purchase electric energy under this section if the FERC finds that the conditions set forth in § 292.309(a), (b), or (c) which relieved the obligation to purchase, are no longer met.

### **Termination of obligation to sell to qualifying facilities (§ 292.312)**

(a) Any electric utility may file an application with the FERC 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 FERC 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 FERC 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.

### **Reinstatement of obligation to sell (§ 292.313)**

At any time after the FERC 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 FERC 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 FERC must issue an order within 90 days of such application reinstating the electric utility's obligation to sell electric energy under this section if the FERC finds that the conditions set forth in paragraphs (b)(1) and (b)(2) of this section are no longer met.

#### **Existing rights and remedies (§ 292.314)**

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 non-regulated 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).

#### **EPAct 2005 – Opt-Out Provisions in Competitive Markets**

PURPA as originally enacted contained “must-purchase” and “must-sell” obligations that applied to all electric utilities, including investor-owned utilities, municipalities, rural cooperatives, public utility districts, water districts, the Tennessee Valley Authority, and each federal power market authority, unless FERC granted a waiver.

The original must-purchase obligation before enactment of EPAct 2005 required the host utilities to purchase at rates equal to the host utility’s full avoided cost, which is “the incremental cost to the electric utility of electric energy or capacity or both, which *but for* (emphasis added) the purchase from the QF or QFs, such utility would generate itself or purchase from another source.” (CFR sec. 292.101(B)(6). Prior to EPAct 2005, states and non-regulated utilities always determined avoided costs, either by determining them administratively or through market-based methods.

The original must-sell obligation before the enactment of EPAct 2005 required each host electric utility to sell to any QF any energy and capacity requested by the QF. The host electric utility is required to provide such electric service to a QF at rates that are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers.

EPAct 2005 provided a new section, section 210(m), that can change both the must-purchase obligation and/or the must-sell obligation of the host electric utilities, should certain conditions exist.

In the case of the must-purchase obligation, the new EPAct 2005 provision requires FERC to 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. The provision specifically 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 competitive wholesale markets: (1) independently administered, auction-based day ahead and real time wholesale markets and wholesale markets for long-term sales of capacity and energy (for example, MISO, PJM, ISO-NE, NYISO), or (2) a regional transmission entity with competitive wholesale markets, or (3) wholesale markets that are comparable to either of the first options.

The short-hand for these three types of wholesale markets are “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 market suffices to meet this requirement for a Day 2 market); “Day 1” markets, which are auction-based real-time markets, but not auction-based day-ahead markets); and comparable markets, respectively.

In Order 688, FERC determined that MISO, PJM, ISO-NE, and the NYISO provide wholesale markets which meet the statutory criteria of a Day 2 market for member utilities to qualify for relief from the mandatory must purchase obligation. FERC Order 688 also created a rebuttable presumption that QFs of more than 20 MW in Day 2 markets have non-discriminatory access to at least one of these competitive markets. And, 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 20 MW has non-discriminatory access to competitive markets. Said another way, FERC determined that QFs of 20 MW or less are presumed to not have non-discriminatory access to one of these competitive markets. The presumption that QFs of 20 MW or less do not have non-discriminatory access to competitive markets is also rebuttable.

FERC’s rationale here is 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 allow 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.

In Order 688, FERC determined that CAISO and SPP were (at that time) Day 1 markets, but made no specific finding as to whether those markets were sufficiently competitive as to their long-term energy and capacity markets. Also, FERC found that ERCOT was a comparable market, that is, comparable to MISO, PJM, ISO-NE, and NYISO. In Order 688, FERC states “there is a rebuttable presumption that QFs

larger than 20 MW operating in ERCOT have nondiscriminatory access to markets.”<sup>35</sup> Again, FERC made no finding as to whether the long-term energy and capacity markets were sufficiently competitive. FERC announced in Order 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, that do not have both auction-based real-time and day-ahead markets) satisfy the statutory requirements for mandatory purchase requirement relief.

EPAct 2005 also changed the must-sell obligation for certain utilities. Under EPAct section 210(m), a host utility’s mandatory obligation to sell can be terminated if FERC finds that: (1) competing retail electric suppliers are willing *and* able to sell and deliver electric energy to the QF; *and* (emphasis added) (2) the electric utility is not required by state law to sell electric energy in its service territory. In other words, the utility no longer has an obligation to serve.

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. For example, at this writing, consider that within most (but not all) of the MISO footprint, the mandatory obligation to sell might persist even though there would not be a mandatory obligation to purchase from QFs of more than 20 MWs. FERC requires that the QF have available at least two competing suppliers who are not affiliated with the interconnecting utility.

The rights or remedies of any party to purchase from or sell electric energy or capacity to a QF under an existing contract or obligation in effect or pending approval of a state public service commission or non-regulated utility at the time of EPAct 2005’s enactment are unaffected. In Order 688, FERC stated that a QF that had initiated, prior to the date of enactment of EPAct 2005, on August 8, 2005, a state PURPA proceeding that may result in a contract or legally enforceable obligation would be considered to have triggered an existing obligation with an electric utility. In Order 688-A, FERC reiterated its finding in *Midwest Renewable Energy Projects, LLC* 116 FERC para. 61,017 (2006) that when a utility refuses to enter into a contract with a QF, and a QF seeks state public service commission assistance to enforce its PURPA regulations, a non-contractual, but nevertheless legally enforceable obligation may be created through the state’s implementation of PURPA. Whether the state regulatory authority’s process for creating a legally enforceable obligation had begun resulting in a legally enforceable obligation being created will be determined on a case-by-case basis, consistent with state law.

FERC did not automatically terminate the QF purchase obligations of any particular electric utility for any particular QF. Neither EPAct 2005 nor FERC in implementing its provisions automatically terminated must purchase obligations, not even for Day 2 markets. Rather, FERC established a procedure that creates only a rebuttable presumption that the QF purchase obligation should be eliminated for particular QFs, if the utility and QF fall within one of the competitive wholesale market provisions.

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<sup>35</sup> FERC Order 688, at para. 179.



Electric utilities must first file applications for relief; QFs in the above markets may, under the rule, then attempt to rebut any presumption of discriminatory access because of operational characteristics or transmission constraints or other constraints. Each QF still has an opportunity to rebut the presumption that it has non-discriminatory access to competitive markets. Recall, either being in a Day 2 market or the existence of an OATT or a reciprocity tariff filed by a non-jurisdictional utility pursuant to FERC's open-access regulations creates the rebuttable presumption that QFs of more than 20 MW have nondiscriminatory access to the relevant wholesale market.

The type of evidence that can be used to overcome the rebuttable presumption that a QF of 20 MW or smaller does not have 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.

A utility electing to file for relief for a mandatory purchase requirement must submit an application to FERC providing certain information, including information about transmission constraints within its service territory. The transmission constraint information is required in order to provide affected QFs information that may be useful in efforts to rebut the presumption that they have access to all aspects of the applicable Day 2 market or access to a competitive wholesale market. Providing studies by the RTO/ISO will be sufficient to meet the information requirement provided the submission is complete. The information required includes information about the applicant's long-term transmission plan, as mentioned, the location of transmission constraints, levels of congestion, system impact studies, as well as OASIS information about available transmission capacity. An electric utility may specify in its application the territory within which it seeks to have its purchase obligation terminated.

Two recent cases before FERC are instructive as to what evidence might overcome the rebuttable presumption that a QF of 20 MW or smaller does not have nondiscriminatory access to competitive markets. In the first case, which involved PPL Electric,<sup>36</sup> FERC denied PPL Electric's request to terminate its mandatory purchase obligation for Souderton QF, which has an expected net capacity of 18.1 MW. PPL Electric based its argument that it could overcome the rebuttable presumption that a QF below 20 MW will not have nondiscriminatory access to a competitive market in the case of Souderton QF. PPL Electric stated that Souderton QF would have no operational constraints that would prevent Souderton QF from participating in the PJM energy and capacity markets. Also, PJM provides nondiscriminatory transmission access to the competitive markets. FERC determined that PPL Electric Utilities had failed to overcome the rebuttable presumption. In particular, FERC stated that it did not appear that any QF-specific studies, for example, an interconnection study that would demonstrated the absence of any specific transmission constraint, had taken place.

FERC also questioned PPL Electric's contention, based on Souderton QF's self-certification, that Souderton QF would sell net capacity into the PJM market. The majority cited with approval an earlier

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<sup>36</sup> PPL Electric Utilities Corporation, Order Denying Application to Terminate Mandatory Purchase Obligation, Dockets QM13-2-000 & QM13-2-001, 145 FERC para. 61,053 (Issued October 17, 2013).



case of *Public Service Commission of New Hampshire*,<sup>37</sup> that held that to overcome the rebuttable presumption, it is not sufficient for a utility to show that market rules permit small QF participation in the markets, that there are no constraints or other barriers to a QF's output reaching the markets, or that other smaller QFs have participated in the market. Instead, the electric utility seeking to rebut the presumption that a small QF lacks nondiscriminatory access must make a QF-specific affirmative showing that the individual QF has access to the markets.

There was, however, an important concurring opinion, by Commissioners Clark and Moeller. While they said they concurred with the overall finding and agreed that PPL's application lacked certain required QF-specific information, such as a system impact study for interconnection, they did not agree that the PJM market rules and planning process were "irrelevant for determining QF-specific market access."<sup>38</sup> They then stated that "it's important the FERC's standard for rebutting the presumption not be set so high as to preclude a utility from being able to make a successful showing before the QF is fully operational and the utility is obligated to purchase."<sup>39</sup> Such an approach would render meaningless the opportunity to rebut the presumption and obtain relief. Rather, the commissioners advocate considering unit-specific information submitted by the applicant alongside the opportunities available to suppliers through open market rules in an RTO. As of this writing, a rehearing has been granted in this case for further consideration.<sup>40</sup>

In the second case, *City of Burlington, Vermont*,<sup>41</sup> is the first case in which FERC granted a request to terminate a mandatory purchase obligation for Chace Mill QF with net capacity of 7.4 MW; that is, a QF below 20 MW in size. After dealing with a procedural issue on standing, FERC accepted Burlington's evidence that Chace Mill QF had sold into the ISO-NE markets since April 1, 2013, demonstrating that Chace Mill had nondiscriminatory market access. Furthermore, Chace Mill either had continuing access through VEPPi, Vermont's electricity purchase power agent, or through Winooski One (hydroelectric generating station), once Winooski One's power purchase agreement with VEPPi had expired, and that ISO-NE operates the New England transmission system on a nondiscriminatory basis. Winooski One, on behalf of Chace Mill, contended that Chace Mill did not have non-discriminatory access out of Burlington's distribution system, specifically a 13.8 kv radial distribution line, and that Burlington did not have a FERC-approved reciprocity tariff. But, FERC noted that Burlington had allowed continuing access, subject to reasonable interconnection or distribution. The Commission also found to be significant Chace Mill's affiliate connection with GDF Suez, an active participant in ISO-NE's markets. Based on these QF-specific findings and the finding that NE-ISO provided nondiscriminatory access to its transmission facilities to reach its market, FERC held that Burlington had rebutted the presumption that this particular small QF lacked nondiscriminatory access to a competitive wholesale market.

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<sup>37</sup> 131 FERC para. 61.027 (2010), reh'g denied, 134 FERC para. 61,041 (3013).

<sup>38</sup> Concurring opinion, at 1.

<sup>39</sup> *Ibid.* at 2.

<sup>40</sup> See PPL Electric Utilities Corporation, Order Granting Rehearing for Further Consideration, Docket QM13-2002 (Issued December 16, 2013).

<sup>41</sup> Ordering Granting the Application to Terminate Mandatory Purchase Obligation, Docket QM13-4-000, 145 FERC para. 61,121 (issued Nov. 13, 2013).

One additional item bears mentioning. FERC made no finding as to whether Winooski One was entitled to a contract or legally enforceable obligation and whether that contract or enforceable obligation would be grandfathered. This is relevant as Winooski One initiated a state proceeding before the City of Burlington filed its petition for relief from its mandatory purchase obligations. FERC Chairman Jon Wellinghoff dissented in this case, basically disagreeing with the majority's characterization of the evidence.<sup>42</sup> According to Chairman Wellinghoff, the role of VEPPi in reselling the power into the ISO-NE market was irrelevant as to whether Chace Mill has access to the markets. Chairman Wellinghoff would have required more specific evidence from Burlington of the nature and extent of Chace Mill's sales to the ISO-NE market. Chairman Wellinghoff found the reliance on a 13.8 kv radial distribution system line as Chace Mill's only potential path to a market as evidence that Chace Mill did not have nondiscriminatory access to competitive markets, without more specific evidence to the contrary. He also found that GDF Suez's ownership interest did affect the question of access. Chairman Wellinghoff wrote that he was troubled that Burlington has no reciprocity tariff on file with FERC that would provide open and nondiscriminatory access to a market as well as the uncertainty of future distribution and interconnection charges that Burlington might charge.

In the absence of FERC conditioning the rebuttal of the mandatory purchase obligation upon the filing of a reciprocity tariff or other long-term legal document to provide greater certainty to the QF, Chairman Wellinghoff said he would have found that the utility failed to meet its burden of proof and would not have found this particular QF has non-discriminatory access to the ISO-NE markets. Finally, Chairman Wellinghoff said that if the Vermont Public Service Board had found that Winooski One initiated a proceeding to establish a legally enforceable obligation, then he would have ruled that Winooski One's rights would have been grandfathered and not subject to a petition for relief from mandatory purchase obligations.

These cases suggest that FERC will consider QF-specific information, together with RTO market rule information, as to whether or not a utility has rebutted the presumption that small QF (less than 20 MW) does not have nondiscriminatory access to competitive markets for the purpose of relieving the utility of its mandatory purchase obligation.

## **FERC Regulation Subpart D—Implementation**

### **Implementation of certain reporting requirements (§ 292.401)**

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 FERC's regulations issued under section 133 of PURPA.

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<sup>42</sup> See Chairman Wellinghoff's dissenting statement (issued November 22, 2013).

### **Waivers (§ 292.402)**

(a) State regulatory authority and non-regulated electric utility waivers. Any state regulatory authority (with respect to any electric utility over which it has ratemaking authority) or non-regulated 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) FERC 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.

## **FERC Regulation Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations<sup>43</sup>**

### **FERC Rule: Exemption to qualifying facilities from the Federal Power Act (§ 292.601)**

(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 PURPA section 210, 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.

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<sup>43</sup> Subpart E is marked as “Reserved” in the Code of Federal Regulations, and hence skips to Subpart F.

### **Exemption to qualifying facilities from the Public Utility Holding Company Act of 2005 and certain State laws and regulations (§ 292.602)**

(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 MW if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) Exemption from the PUHCA 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 exempted (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 non-regulated electric utility, the FERC may consider a limitation on the exemptions specified in paragraph (b)(1) of this section.

(4) Upon request of any person, the FERC may determine whether a qualifying facility is exempt from a particular State law or regulation.

## What Is a Qualifying Facility?

There are two steps to achieve QF status. One is to become certified (unless exempt). The other is to enter into a legally enforceable obligation and/or to negotiate a contract with the utility that will be purchasing power from or selling power to the QF. On March 19, 2012, FERC issued Order 732, which revised its regulations on how to certify a QF. Prior to Order 732, there were two paths to QF certification. The first path was self-certification, which required no filing with FERC. The second path was FERC certification. When a small power production facility or cogeneration facility self-certifies, it certifies that it satisfies the requirements for QF status. FERC does not formally review the self-certification. Instead, the self-certification is assigned a docket number and FERC staff looks at the filing to determine that the self-certifier has provided the information required by the regulations. Self-certification was purely a notice for informational purposes. The QF needed to provide FERC Form No. 556 to certify QF status for an existing or proposed small power production or cogeneration facility. Indeed, QF status was established by meeting the requirements and did not depend on the QF filing.

FERC recognized that QFs and purchasing utilities could agree that a generating facility met the QF status requirements and the facility would qualify for the QF benefits of PURPA without making any filings with FERC whatsoever. The second path, FERC certification path, was optional. Under this optional procedure, an entity may file an application for determination by FERC that the facility meets the requirements for QF status. The application required a filing fee. Then FERC assigned the filing a docket number and placed a notice in the Federal Register, providing an opportunity for interventions and comment. FERC acted on the application within 90 days of the filing of the application or its supplement or amendment. (QFs may want or need FERC certification in order to meet lender requirements, or requirements of electric utilities or state regulators that a generator seeking QF status be FERC-certified.) The system worked well until the enactment of EPCAct 2005.

As discussed in Section I.D [above](#), EPCAct 2005 imposed new technology requirements for QF status for “new cogeneration” facilities. FERC issued Order 671 to implement those new requirements. As part of that implementation, notices of self-certification for new cogeneration facilities for the first time were required to be published in the Federal Register; other self-certifications for other than new cogeneration facilities were not filed in the Federal Register. FERC also required the filing of a notice of self-certification or an application for FERC certification as a requirement for QF status.

In FERC Order 732, issued on March 19, 2010, FERC made its most recent revision to the form, procedures, and criteria for certification of QF status for a small power production or cogeneration facility. In Order 732, FERC provided that an applicant seeking to certify QF status for a small power production or cogeneration facility must complete and electronically file the Form 556 that is in effect at the time of the filing. FERC also adopted an exemption for applicants with generation facilities seeking QF status with net power production capacities of 1 MW or less. To be a QF, small power production and cogeneration facilities with 1 MW or less of net production capacity do not need to file a notice of self-certification nor a FERC application for certification for QF status to obtain QF status. Order 732 also codifies FERC’s authority to waive the QF certification requirement for good cause. All applicants for QF certification (those with greater than 1 MW net power production capacity) are required to serve

a copy of a filed Form 556 on the affected utilities and state regulatory authorities. The requirement that applicants provide a draft notice suitable for publication in the Federal Register was eliminated.

The second step to gaining QF status is to enter into a negotiated agreement with its host utility or to have established a legally enforceable obligation. In *Midwest Renewable Energy Projects, LLC*, 116 FERC para 61,017 (2006), FERC made it clear that either a contract or a legally enforceable obligation create PURPA rights, but that they are not synonymous terms. It is easy enough to determine whether a utility and a QF have entered into a negotiated agreement; state contract law applies. It is much more difficult to determine whether and when a legally enforceable obligation was established. (Note, in some cases a legally enforceable obligation is established before a negotiated contract is entered into by both parties. In such cases, the negotiated agreement would, according to its own terms, supersede the legally enforceable obligation.)

As discussed in FERC Order 668-A, when a utility refuses to enter into a contract with a QF, and the QF seeks state regulatory commission assistance to enforce its PURPA regulatory rights, a non-contractual, but still legally enforceable obligation may be created pursuant to the state's implementation of PURPA. The legally enforceable obligation does not necessarily involve a single writing containing all material terms and how the QF may initiate the process varies widely from state to state. What is a legally enforceable obligation is established through a state's implementation of PURPA. But, state PURPA proceedings that may result in a contract or a legally enforceable obligation would be considered to have triggered an obligation with the electric utility. When an obligation under PURPA is established is the date such an obligation is established by each state commission or non-regulated utility.

FERC has determined, however, that a QF that has initiated a state PURPA proceeding prior to an applicable electric utility filing will be entitled to have the contract or obligation that may be established by state law grandfathered. Indeed contracts or obligations that are being pursued in the context of state commission proceedings that were pending on the date of the enactment of EPCA 2005 fall within the section 210(m)(6) saving clause. FERC left open the possibility for QFs that believe that some sort of state proceeding has created a legally enforceable obligation under state law to argue their claim before FERC, and FERC will make the determination on a case-by-case basis based on state law. This includes whether the issue of whether a QF has a legally enforceable obligation under a "build first" state law if the QF had already begun but not yet completed physical construction of the QF facility. Obviously, whether and when a legally enforceable obligation or an obligation has been created has become a difficult area for state commissions and non-regulated utilities to deal with. As discussed in Section [III Recent FERC Cases](#), this issue in particular has become a flashpoint of controversy.

The importance of whether a utility has a legally enforceable obligation also becomes critical in implementing EPCA 2005 Section 210(m)(1), which was discussed [above](#). That section states that no electric utility "shall be required to enter into a new contract or obligation" to purchase electric energy from a QF if the FERC makes the required finding. In Order 688, FERC found that when a contract terminates by its own accord, an electric utility is not compelled to enter into a new, successor contract

with the QF if the FERC has found that the QF has nondiscriminatory access to markets that satisfy the criteria of section 210(m)(1).

Determining when a contract expires according to its own terms is relatively straightforward. But what is more difficult is dealing with the termination of a preexisting legally enforceable obligation. Some have alleged that the grant of QF status means that electric utilities have an “obligation” to purchase from that QF in perpetuity. FERC made clear in Order 688 that QF status does not mean that an electric utility has an “obligation” to purchase from the QF in perpetuity, or, conversely, that the QF has the right to demand that the utility purchase at avoided-cost rates in perpetuity. Instead FERC found that if a contract is entered into after August 8, 2005, the date of enactment of EPAct 2005, but before the FERC has determined that an electric utility is entitled to relief from the obligation to purchase from a QF, the contract already entered into will be treated as though it was in effect on August 8, 2005 for purposes of section 210(m)(1). However, the underlying issue raised of when legally enforceable obligations, without explicit specified fixed terms, expire still remains.

## FERC Regulations on hydroelectric small power production facilities

### §292.203 (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.

### *Special requirements for hydroelectric small power production facilities located at a new dam or diversion (§ 292.208)*

(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 FERC 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 FERC 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

#### §292.202 Definitions

(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



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 FERC 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.

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

(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 FERC 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 FERC 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.

***Petition alleging commitment of substantial monetary resources before October 16, 1986 (§ 292.210)***

(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.

(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.

***Petition for initial determination on whether a project has a substantial adverse effect on the environment (AEE petition) (§ 292.211)***

(a) An applicant that has filed a petition under § 292.210 may also file an adverse effect on the environment (AEE) petition with the FERC 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 FERC 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 interveners 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.
- (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 FERC 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 FERC 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.

### III Recent PURPA-Related Cases

Under PURPA section 210 (H)(2)(A), (B), FERC has discretionary power to enforce the PURPA rules against state commissions and non-regulated utilities; that is, to require that state commissions and non-regulated utilities comply with FERC's PURPA rules when they are not implementing them properly. Under the PURPA QF regulatory scheme, states are required to implement FERC's PURPA rules. In practice, FERC PURPA enforcement works in the following manner: QFs and utilities concerned about a state commission's implementation of PURPA file a petition with FERC requesting that FERC exercise its statutory enforcement authority against a state commission or non-regulated utility.

FERC relies heavily on state commissions and non-regulated utilities to assure that the host utility pays a QF its full avoided costs or a negotiated rate for purchased power. FERC regulations require that states and non-regulated utilities have standard offer rates for purchases from QFs with design capacity of 100 kW or less. State commissions and non-regulated utilities may also have standard offer rates for purchases from QFs with a design capacity of over 100 kW. While nothing in FERC's regulations requires any electric utility to pay more than its avoided costs for purchases, standard offer rates may differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies.

The avoided costs paid for purchases from QFs can be based upon estimates of avoided costs over the specified term of a contract or legally enforceable obligation – thus, the rates for purchase can differ from the avoided cost at the time of delivery. Alternatively, rates for “as available” power can be based on the time of delivery.

FERC has also relied heavily on state commissions and non-regulated utilities to determine rates for sales (sec. 292.305) by utilities to QFs. In addition to services normally available to all customers, FERC regulations require that each host electric utility provide its QFs, upon request, supplemental power, back-up power, maintenance power, and interruptible power (see [Why Become a QF?](#) and [Rates for sales \(§ 292.305\)](#)). FERC regulations require that these rates be just and reasonable, in the public interest, and non-discriminatory against any QF in comparison to rates for sales of such services to other customers. The rates for sale are to be based on accurate data and consistent system-wide costing principles that are not discriminatory against any QF to the extent that the rates also apply to the utility's other customers with similar load or other cost-related characteristics. State commissions and non-regulated utilities determine these rates.

Finally, state commissions and non-regulated utilities are required to calculate non-discriminatory interconnection costs for the QF to pay for the cost of interconnection in fulfillment of PURPA's obligation to interconnect ([see above](#)).

What follows is a digest of FERC enforcement actions in Federal District Court, as well as FERC dockets initiated by the requests of QFs for FERC to initiate its PURPA enforcement authority. The cases span the time period of November 4, 2011 to December 31, 2013.

*FERC v. Idaho Public Utilities Commission* (U.S.D.C. (ID) case no. 1:13-cv-00141)

On March 23, 2013, FERC filed a complaint against the Idaho PUC in United States District Court. The action was in response to petitions for enforcement filed at FERC by QFs, *Grouse Creek*, *Murphy Flat*, and *Rainbow Ranch*, against the Idaho PUC, seeking injunctive and other relief in light of FERC Orders announcing intent to enforce PURPA regulations permitting a QF to sell energy pursuant to a legally enforceable obligation. (FERC issued its Notice of Intent to Act and Declaratory Order in *Murphy Flat* on November 20, 2012. See EL12-108.) In a third proceeding dealing with *Rainbow Ranch Wind*, FERC reversed its April 20th, 2012 decision not to act and said on July 2, 2013 that it is appropriate to initiate an enforcement action. All three of these cases have similar factual situations that raise the issue of under what circumstances a host utility has a legally enforceable obligation to purchase from a QF when a standard avoided cost rate eligibility cap has been changed.

The action was dismissed by the District Court on December 27, 2013, because a stipulation was entered. The stipulation came in the form of a Memorandum of Agreement (MOA) between the FERC and the Idaho PUC. In the MOA, FERC and the Idaho PUC acknowledged that PURPA established a program of cooperative federalism, under which FERC issued regulations to give effect to federal policy to encourage small power production development. State commissions, such as the Idaho PUC, are responsible for implementing 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 FERC's PURPA regulations. The Idaho PUC additionally acknowledges that a legally enforceable obligation may be incurred prior to formal memorialization of a contract to writing.<sup>44</sup>

*Idaho Power v. Grouse Creek* (Idaho Supreme Court, 2013 Opinion No. 135)

The Idaho Supreme Court, in *Idaho Power v. Grouse Creek* (Idaho Supreme Court, 2013 Opinion No. 135, Docket 39151, issued December 18, 2013), affirmed the Idaho PUC's order denying approval of contracts between Idaho Power and Grouse Creek on the grounds that the filed purchase power contract was contrary to public policy because it exceeded the utility's avoided costs. The Idaho PUC declined to approve the purchase power agreements between Idaho Power and Grouse Creek because on the effective date of the agreements, December 18, 2010, Grouse Creek's 10 MW project exceeded the eligibility cap, which became effective December 14, 2010 for published avoided cost rates. The Idaho Supreme Court affirmed the Idaho PUC's requirement that for a legally enforceable obligation to be in existence before a signed contract would require a showing that there would have been a contract but for the actions of the utility. The Court upheld the Idaho PUC's finding that Idaho Power was not at fault for the lack of a signed contract and held that the Idaho PUC's finding was supported by substantial and competent evidence. The Court further noted that the parties' contracts provided that the agreement was contingent on Idaho PUC approval. The Court held that the federal PURPA regulations did not require the Idaho PUC to approve the rates set forth in the purchase power agreements, rates

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<sup>44</sup> See the Memorandum of Agreement at <https://www.ferc.gov/legal/mou/mou-idaho-12-2013.pdf>.



which would have been in effect before the eligibility cap went into effect. And the Court held that allowing Grouse Creek to sell power at rates in place prior to the eligibility cap adjustment would not have been in the public interest.

#### *Cedar Creek Wind*

FERC on November 4, 2011 issued a Notice of an Intent not to Act on an enforcement petition, despite a finding that five firm energy sales agreements between Cedar Creek Wind, and PacifiCorp d/b/a Rocky Mountain Power were inconsistent with PURPA's requirements and FERC regulations. FERC found that the Idaho PUC's decision denying Cedar Creek had established a legally enforceable obligation, based specifically on a June 8th Idaho Order requiring a Firm Energy Sales Agreement / Power Purchase Agreement must be executed by both parties to the agreement before a legally enforceable obligation arises, is inconsistent with PURPA and FERC regulations. On reconsideration, the Idaho PUC found that Cedar Creek had perfected a legally enforceable obligation and approved modified contracts at the previous avoided cost rates.

#### *Idaho Wind Partners*

FERC on September 20, 2012, granted a petition (in Docket EL12-74) filed by Idaho Wind Partners which requested that FERC find that the proposed tariff revision, adding a Schedule 74, filed by the Idaho Power Company concerning Idaho Power's curtailment of energy and capacity purchases from QFs would violate PURPA and the regulations implementing PURPA. This is not an enforcement case, but it is rather a Declaratory Order case. Idaho Wind did not allege that Idaho Power had violated PURPA or its regulations as related to the curtailment issue. The Idaho PUC had not yet addressed the curtailment issue when Idaho Wind filed its petition with FERC.

Schedule 74 (if approved by the Idaho PUC) would have allowed Idaho Power to curtail energy and capacity purchases during light loading situations. The PUC disapproved Schedule 74 on other grounds. The light loading rule is one of the three recognized exemptions from purchasing QF power. The other two are utility system emergency and proof under EPCA 2005 that a QF with a new contract or legally enforceable obligation can gain access to competitive markets as an alternative outlet for sales to the host utility. (This later exemption is discussed in further detail [here](#) and [here](#).)

Curtailment of energy and capacity purchases during light loading situation is allowed under FERC regulation section 304(f), also known as the light loading rule. As FERC had explained in FERC Order 69 utilities are exempt from buying under PURPA if the QF ends up costing the utility more than it saves, that is during certain minimum loading situations. That can occur if QF power is delivered during lightly loaded off-peak hours. In such a situation, for example, when a coal plant would need to be ramped down to free up load for a QF, but then be unable to quickly ramp back up, that would mean that rather than avoiding costs, the utility would be incurring additional incremental costs because of the QF power. In other words, the QF avoided costs would be negative. The light loading rule was established to prevent that from occurring.

As FERC further explained in Order 69, however, the light loading rule is not intended to override contractual or other legally enforceable obligations incurred by the electric utility to purchase power from a QF. In a 2011 case involving Entergy, FERC stated that utilities couldn't exempt themselves from buying QF power simply because a QF is intermittent (solar or wind-powered), selling only unscheduled, non-firm energy. Docket ER05-1065-011, Dec. 15, 2011, 137 FERC para. 61,199. The light-loading exemption cannot be relied upon to curtail purchases of unscheduled QF energy for general economic reason.

In denying a petition for rehearing on June 20, 2013 in the Idaho Wind Partners proceeding (EL12-74), FERC rejected an Idaho Power argument that FERC's decision that the Schedule 74 tariff revision supplanted the Idaho PUC's role in the PURPA process because FERC issued a declaratory order invalidating Schedule 74 before the Idaho PUC acted. FERC responded that it had issued the declaratory order to terminate controversy and to remove uncertainty because if Schedule 74 had been approved by the Idaho PUC, it would have been inconsistent with PURPA and FERC's regulations implementing PURPA.

#### *Interconnect Solar Development*

FERC issued a Notice of an Intent Not to Act against the Idaho PUC and Idaho Power. The case involved an Idaho PUC decision to uphold Idaho Power's cancellation of its Firm Energy Sales Agreement (FESA) with Interconnect Solar Development based on a finding that Interconnect Solar breached the FESA because Interconnect Solar had failed to pay a \$900,000 security deposit for delay-related liquidated damages. FERC offered no reason for its decision.

#### *Pioneer Wind*

On October 2, 2013, Pioneer Wind Park I, LLC (hereafter Pioneer Wind) located in Wyoming filed a petition with FERC requesting that FERC issue an order finding that PacifiCorp's refusal to execute a Power Purchase Agreement with Pioneer Wind unless Pioneer Wind agrees to allow PacifiCorp to curtail the Pioneer Wind project ahead of other generators, as if it were a non-firm transmission customer, is inconsistent with PURPA regulations, and that Pioneer Wind is entitled to network resource interconnection service under the PacifiCorp's standard Large Generator Interconnection Agreement. Pioneer Wind also requested that FERC declare that PacifiCorp's October 18th Amendment filed at the Wyoming Public Service Commission would be inconsistent with PURPA and its regulations.

In *Pioneer Wind Park I, LLC, Order Granting Petition for Declaratory Order In Part*, Docket EL14-1-000, 145 FERC para. 61,215 (Issued December 16, 2013), FERC found that the proposed curtailment provision violates PURPA and its regulations. The regulation only permits 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." However, that is not the case here. Pioneer Wind and PacifiCorp intend to enter into a long-term, fixed rate Power Purchase Agreement, based on the avoided costs calculated at the time the obligation is incurred. Under these circumstances, PURPA regulations would only permit PacifiCorp to curtail Pioneer Wind during system emergencies.

As a result, FERC declared the curtailment provisions and the PacifiCorp's October 18th Amendment filed at the Wyoming Public Service Commission to be inconsistent with PURPA and its regulation.

FERC, however, did not step in and determine the avoided costs. It deferred to the Wyoming Public Service Commission to do so. It is the state's responsibility in the first instance to determine avoided cost rates consistent with FERC's PURPA regulations. FERC instructed Pioneer Wind to pursue any of its concerns about the avoided cost calculations with the Wyoming Commission and only if Pioneer Wind is then dissatisfied with the Wyoming Commission's avoided cost calculation may Pioneer Wind file a petition with FERC pursuant to sections 210 (g) or 210 (h)(2)(B) of PURPA.

#### *Gadwall Wind*

On March 18, 2013, Gadwall Wind filed a Petition for Enforcement against the Minnesota PUC to request that FERC require the Minnesota PUC to revise or invalidate a Minnesota Statute defining avoided cost so that they are based on the lower of a purchasing utility's (1) least-cost renewable energy facility, or (2) the bid of a competing supplier of least cost renewable energy facility. (Obviously, the Minnesota PUC cannot invalidate or revise a state statute, although a federal District Court can determine that a state statute is preempted.) On December 19, 2013, FERC issued a notice that it declined to initiate an enforcement action pursuant to section 210(h)(2)(A) of PURPA. FERC decision not to initiate an enforcement action means that Gadwall Wind may, if it so chooses, bring its own enforcement action against the Minnesota Commission in the appropriate court. See *Gadwall Wind LLC v. Minnesota Public Utilities Commission*, Dockets EL13-54-000, QF11-141-002, 145 FERC para. 61,228, December 19, 2013.

#### *Hydrodynamics, Montana Marginal Energy, and WINData*

The issue of whether a legally enforceable obligation exists has also come up in Montana. On June 17, 2013, Hydrodynamics, Montana Marginal Energy, and WINData, who are all managers and/or owners of QFs petitioned FERC to take an enforcement action against the Montana Public Service Commission. The QFs raised the issue of whether the Montana Public Service Commission decisions interpreting its own rule eliminated the rights of Montana QFs to create a legally enforceable obligation and to choose how to sell their energy and capacity. According to the QFs, under the Montana Public Service Commission rule, a QF with an installed capacity greater than the standard offer threshold cannot create a legally enforceable offer or sell its energy or capacity over a specific term using forecasted avoided cost pricing unless the QF either wins a competitive solicitation or successfully negotiates a contract with a utility; according to the QFs, if a QF larger than the standard offer threshold does not win a competitive solicitation, the QF must successfully negotiate a contract with the utility otherwise the QF only has the right to sell its output at an "as available" rate, a short-term rate that does not permit a QF to take advantage of long-term financing as would be the case with a forecasted avoided cost pricing. The Montana PSC disputes the QFs' contention, arguing instead that QFs of any size can obtain a legally

enforceable obligation that sets an avoided cost rate for a specified time period by negotiating with the utility and that the contention that a negotiated rate is impossible is not correct.<sup>45</sup>

### *Kootenai Electric Cooperative*

On June 14, 2013, FERC issued a Notice of Intent Not to Act against the Oregon Public Utility Commission after FERC determined that the designated point of delivery of Kootenai Electric Cooperative's output to Idaho Power was not a substation in Lewiston, Idaho, because it is not the point where actual delivery occurs. *Kootenai Electric Cooperative, Inc.*, 143 FERC para. 61,232 (2013) (June 14 Order). According to FERC, actual delivery occurs at the point where the ownership of the jointly-owned transmission line changes to Idaho Power in Oregon. Idaho Power, which would be the purchasing utility, requested a rehearing at FERC on July 15, 2013. Kootenai Electric Cooperative answered Idaho Power's rehearing request and filed a motion for expedited action. On August 12, 2013, FERC issued a tolling order on rehearing.

This case also deals with the issue of whether a QF has a legally enforceable right to compel an Oregon power purchase agreement under PURPA. In order to understand this case, it is important to know that, although Avista has transmission lines in Oregon, that it does not have a service area for electric service in Oregon. The fundamental dispute is whether electrical (QF) output from Kootenai's Fighting Creek Landfill Gas Station's transmitted via firm, long-term point-to-point transmission creates a legally enforceable obligation in Oregon. Kootenai Electric Cooperative, Inc. (KEC) is a member-owned electric utility in Hayden, Idaho. Kootenai Electric has more than 22,000 member accounts and nearly 2,000 miles of electric line in parts of Kootenai, Benewah, Bonner and Spokane counties. Kootenai Electric is the largest electric cooperative in Idaho. Kootenai contends it has secured long-term point-to-point delivery that would allow Kootenai to deliver Fighting Creek's QF power from across Avista's transmission system near Imnaha, Oregon, where ownership of the jointly-owned transmission line changes from Avista to Idaho Power.

Kootenai exercised its rights under PURPA's regulation in order to wheel power across the Avista system to make an indirect sale to Idaho Power's electrical system in Eastern Oregon. Kootenai's stated objective was to receive the relatively-favorable Oregon approved PURPA rates then in effect and to also retain clear title to the Renewable Energy Credits ([see earlier discussion](#)) generated by the Fighting Creek QF.

FERC confirmed the Avista point-to-point service on August 31, 2012. In February 2013, the Oregon Commission found that Kootenai was not entitled to an Oregon PURPA contract because the energy would not be delivered to the Idaho Power control area within Oregon and that the point of delivery was not in Oregon.

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<sup>45</sup> During the final editing of this Manual, FERC issued a Notice of Intent Not to Act and Declaratory Order, on March 20, 2014 in Dockets EL13-73-000, et al., see <http://www.ferc.gov/whats-new/comm-meet/2014/032014/E-13.pdf>.

While FERC issued its Notice of Intent Not to Act, it also issued a Declaratory Order that an Oregon order is inconsistent with PURPA and that Kootenai may bring its own enforcement action against the Oregon Commission in the appropriate United States District Court. On December 19, 2013, the FERC issued an Order Denying Idaho Power's Request for Reconsideration of its June 14, 2013 Order. Kootenai Electric Cooperative, Inc., 145 FERC para. 61,229 (2013).

#### *Otter Creek Solar*

On June 27, 2013, FERC issued a Notice of Intent Not Act, declining an Otter Creek Solar (QF) request to initiate an enforcement action against the Vermont Public Service Board. FERC found that the Vermont Board's standard offer SPEED program, which the Otter Creek QF objected to, is an optional program available to certain small renewable QFs. Those Vermont QFs that choose to participate in the SPEED program are agreeing to the rates that result from the SPEED program. Alternatively, QFs may still participate in the Vermont Board's longstanding Rule 4.100 program, which FERC has previously found to be consistent with PURPA. FERC found that nothing in FERC's regulation limits the authority of either an electric utility or a QF to agree to rates for any purchase or terms or conditions relating to any purchases which differ from the rates, terms, or conditions which would otherwise be required by FERC's regulations.

#### *Winding Creek Solar*

On August 12, 2013, FERC issued a brief Notice of Intent Not to Act, declining to initiate an enforcement action against the California PUC. Instead, FERC stated that the QF-Petitioners, Winding Creek Solar, may bring its own enforcement action against the California PUC in an appropriate court. Winding Creek Solar asked FERC to initiate an enforcement action against the California PUC on the grounds that, according to Winding Creek Solar, the California PUC Feed-In Tariff program, called Re-MAT program is contrary to PURPA and FERC's regulations, because the Re-MAT or Renewable Market Adjusting Tariff Program fixes the wholesale price for the purchase of QF power at a price that hasn't been determined to be the utility's full-long term avoided costs and the Re-MATS rule eliminates a QF's ability to seek an avoided cost long-run rate except through the Re-MAT programs. Winding Creek also challenged the California PUC policy that, outside of the Re-MAT program, new smaller QFs are only entitled to a short-term rate as opposed to a longer-term at the time the obligation is incurred. The California PUC contends that there is no basis for enforcement and that PURPA and FERC's regulation do not mandate that avoided cost must be based on fossil fuel generation. (Recall previous discussion of [California's Feed-In Tariff](#).) The California utilities (Southern Cal. Edison and PG&E) answered that a long-term contract at a price based upon avoided cost calculation is available at the time of a purchase power agreement execution through means of a legally enforceable obligation in the California standard PURPA 20 MW PPA offer. The avoided costs are calculated at the time the obligation is incurred.

#### *Midland Power Cooperative*

A proceeding in Iowa has been particularly troubling as it may involve encroachment upon retail jurisdiction. The Sweckers, retail customers of Midland Power Cooperative, bought a 65 kW QF wind

generator. The Sweckers and Midland have battled over interconnection charges and calculation of avoided costs. Midland disconnected the Sweckers over billing disputes involving non-payment. On December 15, 2011 FERC found (in Docket EL11-39) that the actions of Midland Power Cooperative in disconnecting service to a QF, owned by the Sweckers, were inconsistent with its obligation under PURPA. FERC held that disconnection should not occur without following FERC's regulations for authorization to be relieved of the obligation to sell power to the QF. On January 17, 2012, the Iowa Utilities Board protested that FERC's order to reconnect the Sweckers was not a dispute over avoided cost rates. (The issue of net-back billing is raised. See the earlier discussion.) The avoided cost rate that Midland pays the Sweckers is the same rate paid to other QFs within its exclusive territory and is in compliance with the Iowa Utilities Board's non-discrimination policy. Rather, the disconnection of retail service was for non-payment of retail services, which is clearly and solely within the jurisdiction of the Iowa Utilities Board. FERC on March 21, 2013 denied requests for rehearing, but has also renewed its Notice of Intent Not to Act. On May 17, 2013 Midland Power Coop and the National Rural Electric Coop Association (NRECA) asked the DC Circuit Court of Appeals to review FERC's orders. NARUC intervened in support on June 7, 2013 and the Iowa Utilities Board filed an intervention on June 17, 2013. APPA also intervened in support of Midland Power Cooperative and NRECA in this case.

#### *Exelon Wind QFs*

A final significant FERC case that does not, at this time, involve a state commission is *Exelon Wind QFs v. Excel Energy Services & Southwestern Public Service Company*, FERC Docket EL13-61. Exelon Wind QFs (hereinafter Exelon) has been involved in numerous proceedings before the Public Utility Commission of Texas and in federal and state proceedings. The Exelon Wind QFs involved in this case are located in the panhandle of Texas within the Southwest Power Pool and outside of ERCOT. Exelon is claiming a loss of \$78 million in avoided cost due from Xcel and its operating subsidiary the Southwestern Public Service Company. They are seeking FERC to enforce Xcel/SPS's obligation to comply with FERC's regulations including the PURPA purchase obligation. Exelon contends that it has consistent with requirements of FERC and the PUC of Texas established legally enforceable obligation with SPS and that Exelon has elected to sell its output to SPS at forecasted avoided cost rates for a 20-year term commencing the date on which the facility commenced deliveries to SPS. Xcel/SPS have never acknowledged that a legally enforceable obligation has been formed. In the meantime, there is another related proceeding in Texas. The PUC of Texas approved granting SPS a QF purchase exemption in case of operational circumstances related to transmission congestion or if firm transmission service for delivery of QF output would be impossible without additional grid upgrades. The PUC of Texas also ruled that SPS could calculate avoided cost rates based on the locational imbalance price in the SPP Energy Imbalance Service as determined at the location specific to the QF. (These are unique and original approaches.) Exelon refused to voluntarily register in the EIS market. SPP claims this is a breach. Exelon claims that SPP's Day One EIS market is actually an ancillary service (imbalance service) market and not an energy market and that any calculation of avoided cost rates based on the locational imbalance price would deny Exelon its full avoided costs. They made this contention in Petition for Enforcement and Declaratory Order, FERC Docket EL12-80, filed June 29, 2012.

## *Several Final Observations on Evolving Issues*

### Legally Enforceable Obligations

Even upon initial resolution that a legally enforceable obligation exists, the issue of what the existence of a legally enforceable obligation means can sometimes be elusive. In circumstances where there is a standard tariff or a standard contract that would apply, it is clear that the legally enforceable obligation would be that the standard tariff or contract applies. The FERC has also made it clear that there need not be an expressed, written contract in place for there to be a legally enforceable obligation. But, under circumstances where a legally enforceable obligation is found and no standard tariff would apply, what does a legally enforceable obligation mean? There is no clear guidance in the FERC cases. However, to be consistent with the PURPA regulations, one would expect that a legally enforceable obligation under such circumstances would require the utility and the qualifying facility to successfully negotiate the terms and conditions of a contract to purchase power from a qualifying facility at its full avoided costs (and/or sell power to the qualifying facility at non-discriminatory just and reasonable rates). In other words, a legally enforceable obligation for a utility to purchase QF power would require, at a minimum, the QF and the utility to reach an agreement where the QF is compensated no more than its full avoided costs and the QF obligates itself to sell its power to the utility as of a set date and for a set term. The proper forum for such a determination that a legally enforceable obligation exists would be at the state commission. The state commission in determining whether a legally enforceable obligation exists might require the QF to demonstrate its viability and hence its ability to sell its power to the utility. State commissions might balance the desirability of requirements for a QF to demonstrate its viability against PURPA's purpose of encouraging efficient QF power development, keeping in mind that the existence of a legally enforceable obligation might be required for the QF to obtain necessary financing.<sup>46</sup> If a legally enforceable obligation is found, and should the QF and utility fail to reach an explicit agreement, one possibility would be for third-party negotiation (or negotiation-arbitration) to take place at the state commission. Requiring successful negotiation of terms and conditions to a purchase power agreement involving a qualifying facility not subject to a standard contract or tariff could involve expedited negotiations, possibly facilitated by a third-party, with the possibility of arbitration, should negotiations fail.<sup>47</sup> State commissions in the past have facilitated a similar role in regards to implementation of the Telecommunications Act of 1998.<sup>48</sup>

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<sup>46</sup> A discussion of several state approaches to defining a legally enforceable obligation can be found on pages 16 to 30 of <http://puc.sd.gov/commission/dockets/electric/2011/EL11-006/nwenergybrief.pdf>.

<sup>47</sup> See Robert E. Burns, Administrative Procedures for Proactive Regulation (NRRI 87-18). <http://www.ipu.msu.edu/library/pdfs/nrri/Burns-Administrative-Procedures-87-18-Mar-88.pdf>.

<sup>48</sup> See generally, NRRI, State Commission Mediation and Arbitration of Interconnection Agreements: Procedures and Status under the Telecommunications Act of 1996 (NRRI 96-24), <http://www.ipu.msu.edu/library/pdfs/nrri/Davis-Zearfoss-Commission-Mediation-96-24-Sept-96.pdf>. (These NRRI Reports are available both on the National Regulatory Research Institute and Michigan State University – Institute of Public Utilities websites.)



## The Issue of Curtailment and Light Loading

Another area of continuing concern is the issue of curtailment and light loading. A discussion on this also appears in [Periods during which Purchases are not required](#). FERC's interpretation is that all existing long-term purchased power agreements (other than "as available") incorporated avoided-cost rates that were calculated at the time the legally enforceable obligation was incurred, inherently including fluctuations in rates because of operational circumstances during light loading periods. FERC's current approach that curtailment during light loading periods is not permitted where there is a long-term purchase power agreement provides certainty for the QF, but places a burden on the utility and its ratepayers to pay more than the utility would have had to had the utility not purchased the QF's power. Light loading situations can result in the utility paying more to dispatch higher cost power than they would have otherwise. Forecasting, that is predicting and estimating, the size and length of occurrence of light load situations can be difficult, if not impossible, over the long-term. Unforeseen circumstances can change the likelihood and substantially increase the risk of light loading circumstances, where the ability to curtail QF power would result in lower overall rates. Examples of changing circumstances include must-run hydroelectric power during increasingly variable drought-deluge cycles as well as the increased likelihood of must-run reliability fossil fuel plants as a result of MATS-related fossil plant retirement. State commissions might consider the value, the benefit of inclusion or the cost of exclusion, of curtailment provisions that provide utility operational flexibility in setting avoided cost rates for new purchased power agreements, including agreements reached after existing agreements or legally enforceable obligations expire.

## Cooperative Federalism

Clear and consistent guidance is difficult to derive from a case-by-case approach entailed by enforcement actions. One general observation that can be made from the above cases is that many (but not all) of the actions deal with the issue of whether there is a legally enforceable obligation to purchase QF power to sell to a QF. The Memorandum of Agreement between the FERC and the Idaho PUC could provide an alternative means outside of the federal courts, without resorting to FERC Declaratory Orders. Declaratory Orders, while reducing uncertainty in an individual case, are a poor approach to take into account local conditions and circumstances. An approach, such as that of the Memorandum of Agreement would allow state commissions and the FERC to settle disputes and to make the cooperative federalism framework of PURPA section 210 operate in a manner that both takes into account local conditions and concerns and is consistent with complying with PURPA and FERC's PURPA regulations.



# Code of Federal Regulations

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## Title 18 - Conservation of Power and Water Resources

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### Pt. 292

#### **PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION**

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**Authority:**16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

## **Subpart A—General Provisions**

### **§ 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.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.* Federal Power Act, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267)

[45 FR 12233, Feb. 25, 1980, as amended by Order 575, 60 FR 4856, Jan. 25, 1995]

## **Subpart B—Qualifying Cogeneration and Small Power Production Facilities**

**Authority:**Public Utility Regulatory Policies Act of 1978, (16 U.S.C. 2601, *et seq.*), Energy Supply and Environmental Coordination Act, (15 U.S.C. 791 *et seq.*), Federal Power Act, as amended, (16 U.S.C. 792, *et seq.*), Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*), E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, (15 U.S.C. 3301, *et seq.*).

### **§ 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).

[45 FR 17972, Mar. 20, 1980]

### **§ 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); or
- (3) That is used in a space cooling application ( i.e., thermal energy used by an absorption chiller).
- (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 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.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267)

[45 FR 17972, Mar. 20, 1980, as amended at 45 FR 33958, May 21, 1980; 45 FR 66789, Oct. 8, 1980; Order 135, 46 FR 19231, Mar. 30, 1981; 46 FR 32239, June 22, 1981; Order 499, 53 FR 27002, July 18, 1988; Order 575, 60 FR 4857, Jan. 25, 1995]

**§ 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.

[Order 732, 75 FR 15965, Mar. 30, 2010]

**§ 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 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) For purposes of this paragraph, 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.

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility.

(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 maximum size of other small power production facilities within one mile of 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.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15, U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

[45 FR 17972, Mar. 20, 1980, as amended by Order 135, 46 FR 19231, Mar. 30, 1981; Order 575, 60 FR 4857, Jan. 25, 1995; Order 732, 75 FR 15966, Mar. 30, 2010]

## **§ 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).

[45 FR 17972, Mar. 20, 1980, as amended by Order 478, 52 FR 28467, July 30, 1987; Order 575, 60 FR 4857, Jan. 25, 1995; Order 671, 71 FR 7868, Feb. 15, 2006; Order 732, 75 FR 15966, Mar. 30, 2010; 76 FR 50663, Aug. 16, 2011]

## **§ 292.207 Procedures for obtaining qualifying status.**

(a) *Self-certification.* 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 Form No. 556 and filing that form with the Commission, pursuant to § 131.80 of this chapter, and complying with paragraph (c) of this section.

(b) *Optional procedure—(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 Form No. 556 pursuant to § 131.80 of this chapter.

(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) *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.

(d) *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.

[45 FR 17972, Mar. 20, 1980]

**Editorial Note:** For **Federal Register** citations affecting § 292.207, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at [www.fdsys.gov](http://www.fdsys.gov).

## **§ 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.

[Order 499, 53 FR 27003, July 18, 1988]

**§ 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.

[Order 499, 53 FR 27003, July 18, 1988]

**§ 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.

[Order 499, 53 FR 27003, July 18, 1988, as amended by Order 699, 72 FR 45325, Aug. 14, 2007]

**§ 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.

[Order 499, 53 FR 27004, July 18, 1988, as amended by Order 499-A, 53 FR 40724, Oct. 18, 1988; Order 699, 72 FR 45325, Aug. 14, 2007]

### **Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978**

**Authority:** Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 et seq., Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 et seq. Federal Power Act, 16 U.S.C. 792 et seq., Department of Energy Organization Act, 42 U.S.C. 7101 et seq., E.O. 12009, 42 FR 46267.

**Source:** Order 69, 45 FR 12234, Feb. 25, 1980, unless otherwise noted.

#### **§ 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 non-regulated 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.

[45 FR 12234, Feb. 25, 1980; 45 FR 24126, Apr. 9, 1980]

### **§ 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 costs with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection 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.

[Order 688, 71 FR 64372, Nov. 1, 2006; 71 FR 75662, Dec. 18, 2006]

#### **§ 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.

(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.* Each qualifying facility shall have the option either:

(1) 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 purchasing utility's avoided costs calculated at the time of delivery; or

(2) 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, at the option of the qualifying facility exercised prior to the beginning of the specified term, 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.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(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.

(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 § 292.309(a)(1), (2) and (3), 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. If the Commission determines that a market meets the criteria of § 292.309(a)(1), (2) or (3), 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.

(d)(1) For purposes of § 292.309(a)(1), (2), and (3), there is a rebuttable presumption that a qualifying facility with a capacity at or below 20 megawatts does not have nondiscriminatory access to the market.

(2) For purposes of implementing paragraph (d)(1) of this section, the Commission will not be bound by the one-mile standard set forth in § 292.204(a)(2).

(e) Midwest Independent Transmission System Operator (Midwest ISO), PJM Interconnection, L.L.C. (PJM), ISO New England, Inc. (ISO-NE), and New York Independent System Operator (NYISO) qualify

as markets described in § 292.309(a)(1)(i) and (ii), and there is a rebuttable presumption that qualifying 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 (RTO/ISOs) should be relieved of the obligation to purchase electric energy from the qualifying facilities. A qualifying facility may seek to rebut this presumption by demonstrating, *inter alia*, that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or

(2) 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.

(f) The Electric Reliability Council of Texas (ERCOT) qualifies as a market described in § 292.309(a)(3), and there is a rebuttable presumption that qualifying 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. A qualifying facility may seek to rebut this presumption by demonstrating, *inter alia*, that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or

(2) 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.

(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.

[Order 688, 71 FR 64372, Nov. 1, 2006; 71 FR 75662, Dec. 18, 2006]

### **§ 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.

[Order 688, 71 FR 64372, Nov. 1, 2006, as amended by Order 688-A, 72 FR 35892, June 29, 2007]

#### **§ 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.

[Order 688, 71 FR 64372, Nov. 1, 2006]

#### **§ 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.

[Order 688, 71 FR 64372, Nov. 1, 2006; 71 FR 75662, Dec. 18, 2006]

### **§ 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.

[Order 688, 71 FR 64372, Nov. 1, 2006]

### **§ 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 non-regulated 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).

[Order 688, 71 FR 64372, Nov. 1, 2006]

## **Subpart D—Implementation**

**Authority:** Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 et seq., Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 et seq., Federal Power Act, 16 U.S.C. 792 et seq., Department of Energy Organization Act, 42 U.S.C. 7101 et seq., E.O. 12009, 42 FR 46267.

**Source:** Order 69, 45 FR 12236, Feb. 25, 1980, unless otherwise noted.

### **§ 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.

[45 FR 12236, Feb. 25, 1980. Redesignated by Order 541, 57 FR 21734, May 22, 1992]

### **§ 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.

[45 FR 12236, Feb. 25, 1980. Redesignated by Order 541, 57 FR 21734, May 22, 1992]

## **Subpart E [Reserved]**

## **Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration**

## Facilities from Certain Federal and State Laws and Regulations

### § 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.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

[Order 135, 46 FR 19232, Mar. 30, 1981, as amended by Order 569, 59 FR 40470, Aug. 9, 1994; Order 671, 71 FR 7868, Feb. 15, 2006; 72 FR 29063, May 24, 2007; Order 732, 75 FR 15966, Mar. 30, 2010]

### § 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 exempted (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.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

[45 FR 12237, Feb. 25, 1980, as amended by Order 135, 46 FR 19232, Mar. 30, 1981; Order 671, 71 FR 7869, Feb. 15, 2006; Order 671-A, 71 FR 30589, May 30, 2006; Order 732, 75 FR 15966, Mar. 30, 2010; 77 FR 9842, Feb. 21, 2012]