

Bypassing Roadblocks to Renewable
Energy: Understanding Electricity
Law and the Legal Tools Available to
Advance Clean Energy

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INTRODUCTION

Again and again, renewable energy enthusiasts pose the same perplexing question: Why is it so difficult to generate more of our nation’s electricity from clean, renewable resources, and how do we make it happen? The short answer is that the Federal Power Act reserves federal authority over wholesale sales of electricity, which preempts states from setting the wholesale price for electricity generated from renewable resources. As a result, states are limited in their ability to make electricity generated from renewable resources profitable. All is not lost, however, as federal legislation and federal administrative orders continue to chip away at the preemption obstacle of the Federal Power Act. This Comment examines the major federal laws governing the electricity industry in the United States and proposes a creative legal solution that allows green-minded states to bring more electricity generated from renewable resources onto the grid at a price that is fair to renewable generators.

Part I presents the legal obstacles states face when trying to encourage the addition of renewables to the electrical grid by explaining the foundational laws and concepts that affect renewable energy law, including the Federal Power Act (FPA), wholesale versus retail sales of electricity, the Public Utility Regulatory Policies Act (PURPA), and a utility’s avoided cost rate. Additionally, the adverse effects of the Energy Policy Act of 2005 (EPAAct 2005), which amended PURPA to exempt certain utilities from their purchase obligation from qualifying facilities (QF), are discussed. Part II presents the advantages and disadvantages of the different options available to renewable generators to sell their electricity, namely by obtaining QF status or by gaining market-based rate authority. Part III evaluates two Federal Energy Regulatory Commission (FERC) Orders that interpret PURPA in a way favorable to state action on renewables by authorizing feed-in tariffs within the bounds of PURPA. Most importantly, this Comment’s recount of the progression of energy law in the United States from the early 1900s to today will enable the reader to understand and recognize the tools now available to states, which, if properly exercised, could ensure that

the electricity we use today, and in the future, comes from clean, renewable resources.

I

A CHRONOLOGICAL LOOK AT FEDERAL PREEMPTION

One of the primary reasons it is so difficult for states to require increased electricity generation from renewable sources is because a state's authority over electricity is preempted by federal law, through the Federal Power Act (FPA), in important ways. Although the Public Utility Regulatory Policies Act of 1978 (PURPA) and state-empowering orders by the Federal Energy Regulatory Commission (FERC) have reduced the preemption problem, a state still lacks the crucial ability to set the rate that a renewable generator will be paid for its electricity. It is important that states have this power because federal-level action on renewable energy is severely lacking. However, state-level experimentation in renewable energy policy and energy efficiency is robust and has been for years. In fact, twenty-nine states currently have Renewable Portfolio Standards (RPS) that are legally-binding mandates requiring utilities to purchase certain percentages or amounts of electricity from renewable resources.¹ In contrast, although it may sound absurd, the United States still does not have a federal renewable energy policy in place,² nor has it ever had a truly comprehensive energy plan.³ Thus, in order for states to take meaningful steps toward increasing renewable energy generation, the preemption issue must be addressed. Thankfully, as this Comment explains, federal preemption of state authority over wholesale electricity sales is becoming less of an obstacle for state action on renewable energy.

¹ Database of State Incentives for Renewables & Efficiency (DSIRE), *Renewable Portfolio Standard Policies* (Mar. 2013), http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

² *Energy in Brief: What are Renewable Portfolio Standards (RPS) and How do They Affect Renewable Electricity Generation?*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/energy_in_brief/article/renewable_portfolio_standards.cfm (last updated Jan. 25, 2013).

³ JOSEPH P. TOMAIN & RICHARD D. CUDAHY, *ENERGY LAW IN A NUTSHELL* 66 (2d ed. 2011). President Obama's Climate Action Plan, issued on June 25, 2013, is a step in the right direction toward establishing a comprehensive energy plan in the United States. EXEC. OFFICE OF THE PRESIDENT, *THE PRESIDENT'S CLIMATE ACTION PLAN* (2013), available at <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

A. *The Federal Power Act and Wholesale Sales of Electricity*

The FPA creates an obstacle for state authority over renewable energy generation because it prohibits states from setting the rates for wholesale sales of electricity.⁴ Congress passed Part II of the FPA in 1935, explicitly giving the federal government the power to regulate “the sale of electric energy at wholesale in interstate commerce.”⁵ A wholesale sale of electricity is “a sale of electric energy to any person for resale,”⁶ the key word being “resale.” The foundational point to grasp is that the federal government, through FERC,⁷ has sole authority over wholesale sales of electricity. One example of a wholesale sale is when an electricity generator sells its electricity to a “public utility”⁸ that will then resell the electricity to the final user where it is consumed. FERC exercises its authority over wholesale sales by approving the rate (the price of electricity) that a generator can charge when it sells its electricity to a public utility.

The rationale behind FERC’s jurisdiction over wholesale sales of electricity is rooted in the theory that electricity is a part of interstate

⁴ See Federal Power Act of 1920, Pub. L. No. 109-58, § 201, 41 Stat. 1063 (2005) (codified as amended at 16 U.S.C. 824).

⁵ § 201(b)(1); TOMAIN & CUDAHY, *supra* note 3, at 374.

⁶ Federal Power Act § 201(d).

⁷ Congress established the Federal Power Commission (FPC) in 1920 to oversee federally-controlled hydroelectric projects. *History of FERC*, FED. ENERGY REG. COMMISSION, <https://www.ferc.gov/students/ferc/history.asp> (last visited July 13, 2013). Over time, the FPC’s scope of authority greatly expanded, and in 1977, the agency was renamed the Federal Energy Regulatory Commission. TOMAIN & CUDAHY, *supra* note 3, at 380. Today, FERC is the federal agency that is responsible for regulating both transmission and wholesale sales of electricity in interstate commerce, regulating the transmission and wholesale sales of natural gas and oil in interstate commerce, issuing licenses for hydroelectric projects, monitoring and investigating energy markets, and performing many more regulatory functions. *What FERC Does*, FED. ENERGY REG. COMMISSION, <https://www.ferc.gov/about/ferc-does.asp> (last updated May 28, 2013).

⁸ It is important to note that the meaning of a “public utility” is specifically defined in the FPA and is not the same as “electric utilities” or “transmitting utilities” as defined in the FPA. Federal Power Act §§ 3(22)–(23), 201(e). Moreover, when talking about energy law, many people use the term “public utility” inconsistently to refer to a host of different things. For example, the term “public utility” is most appropriately used in reference to consumer-owned utilities that are nonprofit organizations operated on behalf of customers, such as People’s Utility Districts, Municipal Utilities, and Electric Co-operatives. *Oregon’s PUDs: Differences Between Public and Private Utilities*, OR. PEOPLE’S UTIL. D. ASS’N, <http://opuda.org/oregons-puds/> (last visited July 28, 2013). However, “public utility” is also sometimes used to refer to a private, Investor-Owned Utility (IOU) given that the “public” can buy shares of stock in the company and therefore it is “publically held.” IOUs, however, are businesses in the electric industry charged with the purpose of making a profit for owners and shareholders, so it is quite misleading to call an IOU a “public utility.” *Id.*

commerce. The premise is that because the physical nature of electricity is the same regardless of the source that generated it (just a bunch of indistinguishable electrons), once the electricity is sent into one of the major power grids that span multiple states,⁹ there is no way to know whether an electron produced in one state ended up being used within that state or whether it traveled across state lines through the grid and was consumed in another state. Thus, interstate commerce is invoked when electricity enters an interstate grid and FERC maintains sole authority over the wholesale sale of that electricity.¹⁰

Although states do not have authority over wholesale sales, they do have the power to regulate retail sales of electricity.¹¹ A retail sale of electricity is a sale of electricity to the end user;¹² for example, to a customer in his or her home where the electricity is consumed and cannot be resold. However, the problem that results from this split in federal and state authority over electricity sales is that states lack the power to set the rate for electricity from renewable generators. For example, say that a renewable generator in a state produces electricity from a clean, renewable resource and wants to sell it. FERC, a federal agency, holds the authority to approve the rate at which the renewable generator can sell its electricity to a utility; the state has no say about the rate because it is restricted by the FPA. Moreover, because the federal government does not have a renewable energy policy in place,

⁹ ENERGY INFO. ADMIN., U.S. DEP'T OF ENERGY, THE CHANGING STRUCTURE OF THE ELECTRIC POWER INDUSTRY 2000: AN UPDATE 13-14 (2000) [hereinafter EIA, CHANGING STRUCTURE], available at <http://www.eia.gov/electricity/archive/056200.pdf> (there are three major power grids in the United States, the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect; however, the Texas interconnect is not connected with the other two networks and is contained solely within the state of Texas).

¹⁰ See *Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205 (1964). The City of Colton, California, met its entire electric power need by purchasing electricity from Southern California Edison Company, a California company that only sold electricity in California. *Id.* at 206. The California Public Utilities Commission (the state regulatory agency) had been asserting jurisdiction over the Edison-Colton sale for many years. *Id.* However, the FPC stepped in and asserted jurisdiction over the sale, claiming that it was indeed a wholesale sale of electricity in interstate commerce because some of the electricity that Edison sold to Colton was generated out-of-state at the Hoover Dam. *Id.* at 207-08. The Supreme Court held that the FPC properly asserted jurisdiction over the Edison-Colton sale, and it clarified that section 201(b) of the FPA grants plenary jurisdiction to the FPC over all wholesale sales of electricity in interstate commerce that are not expressly exempted by the Act. *Id.* at 217.

¹¹ TOMAIN & CUDAHY, *supra* note 3, at 370.

¹² *Electricity Terms and Definitions*, U.S. ENERGY INFO. ADMIN., <http://www.eia.gov/cneaf/electricity/page/glossary.html#qr> (last visited July 13, 2013).

FERC does not have to take any action to encourage utilities to purchase electricity generated from renewable resources. So naturally, the utility will not buy from a more expensive renewable generator on its own volition; instead, it will purchase electricity from the cheapest source, which is oftentimes also the dirtiest.

In sum, the FPA's grant of federal authority over wholesale sales of electricity severely limits a state's ability to decide which sources will supply its electricity because a state cannot set the rate that a generator will receive for its electricity. However, it is important to note that there are at least a few exceptions to the FPA rule regarding jurisdiction over wholesale sales that are not discussed in this Comment.¹³ It was not until almost sixty years after the passage of the FPA that federal preemption began to subside as Congress instructed FERC to encourage renewable generation and FERC obliged, allowing states more leeway to affect wholesale sales of electricity.

B. PURPA Carves Out an Exception to FPA Preemption

In 1978, Congress enacted the Public Utility Regulatory Policies Act as one of five statutes passed into law under the National Energy Act, which aimed to encourage the development of renewable energy.¹⁴ Congress planned to use section 210 of PURPA to achieve this goal by requiring electric utilities to interconnect with and purchase electricity from qualifying facilities made up of small power producers and cogenerators.¹⁵ A small power producer is defined as "a facility which is an eligible solar, wind, waste, or geothermal facility" or "[a] biomass, waste, renewable resources, geothermal resources [facility], or any combination thereof . . . not greater than 80 megawatts."¹⁶ A cogeneration facility is "a facility which produces— (i) electric energy, and (ii) steam or forms of useful energy (such as

¹³ Federal Power Act § 201(b)(2), (f) (listing exceptions to FERC's jurisdiction); JENNIFER GLEASON, ENVTL. LAW ALLIANCE WORLDWIDE, ADOPTING STATE FEED-IN TARIFF LAWS WITHOUT FEDERAL PREEMPTION 2–4 (2012), available at http://www.elaw.org/system/files/fed.preemption.feb_.29.2012.pdf (listing further exceptions to FERC's jurisdiction, including lack of jurisdiction in Alaska, Hawaii, and Texas because the electric grids in these states do not cross state lines).

¹⁴ EIA, CHANGING STRUCTURE, *supra* note 9, at 31.

¹⁵ Public Utility Regulatory Policies Act of 1978, Pub. L. No. 111-5, § 210(a) (2009) (codified as amended at 16 U.S.C. 824a-3).

¹⁶ Federal Power Act § 3(17)(A) (definitions for some of the terms in PURPA are found in section 3 of the FPA).

heat) which are used for industrial, commercial, heating, or cooling purposes” and meets additional requirements set by FERC.¹⁷

The idea behind section 210 of PURPA was that small renewable generators, QFs, would readily spring up because they were guaranteed to find a buyer for their electricity given that PURPA required electric utilities to purchase electricity from QFs.¹⁸ But it was not that simple. The tricky part was deciding what price the electric utility should be required to pay the QF for its clean electricity. Congress decided that the rate a utility must pay a QF should not exceed “the incremental cost to the electric utility of alternative electric energy,”¹⁹ which is known in the energy world as the utility’s “avoided cost” rate.²⁰ FERC, having been assigned the task of developing regulations to implement PURPA, chose to carve out a small area in which states could set wholesale rates without being preempted by the FPA. After establishing required guidelines for states to follow, FERC allowed states to develop the methodology used to calculate, and ultimately establish, a QF’s avoided cost rate.²¹ However, there was one large caveat—the state-established rate for the QF’s electricity could not exceed the purchasing utility’s avoided cost rate.²²

Avoided costs are defined in the regulations implementing PURPA 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.”²³ Perhaps more clearly explained, avoided cost is the cost the utility would incur to produce its own electricity or to buy electricity from a different source, but instead, the utility will forgo those options and buy electricity from a QF—and will pay the QF this “avoided cost” rate.

However, the requirement that a utility purchase electricity from a QF at the utility’s avoided cost rate is problematic for QFs. Because

¹⁷ § 3(18)(A).

¹⁸ EIA, CHANGING STRUCTURE, *supra* note 9, at 32.

¹⁹ Public Utility Regulatory Policies Act § 210(b).

²⁰ See EIA, CHANGING STRUCTURE, *supra* note 9, at 32.

²¹ CAROLYN ELEFANT, REVIVING PURPA’S PURPOSE: THE LIMITS OF EXISTING STATE AVOIDED COST RATE-MAKING METHODOLOGIES IN SUPPORTING ALTERNATIVE ENERGY DEVELOPMENT AND A PROPOSED PATH FOR REFORM 5 (2011), available at <http://www.recycled-energy.com/images/uploads/Reviving-PURPA.pdf>.

²² *Id.*

²³ 18 C.F.R. § 292.101(b)(6) (2012).

avoided cost is traditionally set at the lowest possible avoided cost to the utility,²⁴ the avoided cost rate typically does not reflect the actual cost that the QF incurred to generate the electricity. (Remember that QFs are small power producers generating electricity from renewable sources, and the technology required by these facilities is generally more expensive than for traditional, carbon-heavy sources.²⁵) Thus, a QF faces a double-edged sword under PURPA. On the one side, the QF is guaranteed that it will find a buyer for its electricity. But on the other side, the price the QF will be paid for its electricity is not based on the actual cost that the QF incurred to produce it.

Tax incentives are one way that a QF can attempt to make up the difference between the cost of generating the electricity and the avoided cost it received for the electricity. However, the tax credit, or even a combination of credits, may not always cover the difference. Furthermore, some of the most attractive tax credits, like the Wind Energy Production Tax Credit (PTC), can make planning difficult because the credit is set to expire periodically.²⁶ Although Congress regularly re-extends the PTC, the uncertainty surrounding its future availability prevents the wind industry from experiencing continuous stability and growth. On the other hand, during the five-year period that Congress did not allow the PTC to expire, “the wind industry experienced a period of consistent year-over-year growth.”²⁷ Thus, the availability of tax credits is incredibly important to the profitability of QFs operating in an avoided cost system, as is plainly evidenced by the U.S. Energy Information Administration’s statement that “the PTC has significantly contributed to wind development in

²⁴ GLEASON, *supra* note 13, at 3.

²⁵ *Renewable Energy Explained*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/energyexplained/index.cfm?page=renewable_home (last updated May 25, 2012).

²⁶ The PTC was originally enacted as part of the 1992 Energy Policy Act and applied to generation from tax-paying owners of new wind plants and eligible biomass power plants, but has since been expanded to include a wider variety of renewable sources. *Wind Energy Tax Credit Set to Expire at the End of 2012*, U.S. ENERGY INFO. ADMIN. (Nov. 21, 2012), <http://www.eia.gov/todayinenergy/detail.cfm?id=8870>. The credit is based on annual production of electricity and is currently valued at 2.2 cents per kilowatthour (2011 dollars) of energy produced from eligible sources. *Id.* However, Congress allowed the PTC to expire three times between 1999 and 2004, and then proceeded to retroactively extend it after the expiration deadline had passed. *Id.* As a result, new wind installations reached high levels in the twelve-month periods preceding the expiration date as developers rushed to beat the expiration deadline, but then dropped off substantially the following year as developers waited to see if Congress would extend the credit again. *Id.*

²⁷ *Id.*

the United States by increasing the financial return on a wind energy investment.”²⁸

C. EAct 2005 Takes the Punch Out of PURPA

The legal framework of PURPA section 210, which increased renewable resource-based electricity generation from QFs, took a considerable hit with the passage of EAct 2005. EAct 2005 added section 210(m) to PURPA, which exempted utilities from their purchase obligation from QFs under certain circumstances. However, to fully understand the rationale behind the section 210(m) amendment, it is necessary to first be familiar with the history of electric power transmission and how transmission access has transitioned from a closed market to a relatively open one.

1. Opening Up Transmission to Allow for a Competitive Market

The structure of the electric power industry is based on the three basic functions of power supply: (1) generation, “the production of electric energy from other energy sources”; (2) transmission, “the delivery of electric energy over high-voltage lines from the power plants to the distribution areas”; and (3) distribution, “the local system of lower voltage lines, substations, and transformers which are used to deliver the electricity to end-use consumers.”²⁹ Thus, the transmission system (or grid) is absolutely essential to the success of the electric power industry because it allows electricity generated at a power plant to reach consumers. However, despite this essential role, transmission historically did not have common carrier status.³⁰ In other words, owners of transmission facilities were allowed to “price discriminate” by charging one generator more than another to use its privately-owned transmission lines and thus exercise substantial control over the electricity market.³¹ By the 1990s, many alternative energy producers could not gain access to transmission, and it was clear that private ownership of transmission facilities presented a significant obstacle to an open and competitive electricity market.³² In 1992,

²⁸ *Id.*

²⁹ EIA, CHANGING STRUCTURE, *supra* note 9, at 9.

³⁰ TOMAIN & CUDAHY, *supra* note 3, at 384.

³¹ *Id.* at 384–85 (explaining that typically a transmission owner also owned generation facilities; thus, the transmission owner always favored itself or its affiliates and essentially prohibited other generators from entering the electricity market).

³² *Id.* at 385–86.

Congress responded to this concern with the Energy Policy Act (EPAAct), which gave FERC broad authority to order owners of transmission facilities to allow other generators to transmit wholesale power over the transmission lines.³³

FERC implemented the EPAAct requirement through Order No. 888, which “require[d] public utilities that own or operate transmission facilities in interstate commerce to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions for non-discriminatory service.”³⁴ Additionally, Order No. 888 required transmission-owning utilities to “functionally unbundle” (i.e., financially separate) transmission service from generation service within the corporation in order to reduce the possibility of self-dealing.³⁵

Order No. 888 and subsequent Order No. 889 made great strides toward creating a competitive electricity market and resulted in the establishment of Independent System Operators (ISOs) that centrally manage and coordinate transmission across wide geographic regions.³⁶ FERC formalized ISOs under the title of Regional Transmission Organizations (RTOs)³⁷ and encouraged, but did not require, transmission-owning utilities to join an RTO.³⁸ An RTO is independent from all participants in the market (i.e., owners of generation and/or transmission facilities and the utilities purchasing electricity) and its job is to “insure that regional wholesale power markets operate efficiently, that all market participants are treated fairly, that all transmission customers have open access, and that the bulk power system is reliable.”³⁹ Currently, ten ISOs/RTOs serve

³³ *Id.* at 387; Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992) (codified as amended at 42 U.S.C. 13201).

³⁴ TOMAIN & CUDAHY, *supra* note 3, at 387–88. See Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 F.E.R.C. ¶ 61,080 at P 4 (Apr. 24, 1996) [hereinafter Order No. 888].

³⁵ TOMAIN & CUDAHY, *supra* note 3, at 388; Order No. 888, *supra* note 34, P 4.

³⁶ TOMAIN & CUDAHY, *supra* note 3, at 389–90.

³⁷ *Id.* at 390.

³⁸ MATTHEW H. BROWN & RICHARD P. SEDANO, NAT’L COUNCIL ON ELECTRICITY POLICY, *ELECTRICITY TRANSMISSION: A PRIMER* 5 (2004), available at <http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/primer.pdf>.

³⁹ TOMAIN & CUDAHY, *supra* note 3, at 396. RTOs can be either a non-profit operator called an ISO or a for-profit operator called a Transco. *Id.* at 392. However, all RTOs “must have: [i]ndependence from market participants, [r]egional scope of operations, [a]uthority to plan and expand, [and] [a]n ‘open architecture’ policy to allow structural modifications.” *Id.* Additionally, RTOs must have sufficient capacity, provide reliable service, manage congestion, not discriminate, and offer reasonable prices. *Id.* at 396. A

two-thirds of the U.S. population and over half of the Canadian population.⁴⁰

2. *Modification of Purchase Obligation from QFs*

In October 2006, FERC issued Order No. 688, which amended its regulations to reflect the changes made to PURPA under EPAct 2005.⁴¹ EPAct 2005 added section 210(m) to PURPA, which terminated the requirement that electric utilities must purchase the electricity generated by QFs, so long as the QF has nondiscriminatory access to one of three kinds of wholesale markets.⁴² The QF must have access to (1) “independently administered, auction-based day ahead and real time wholesale markets” and “wholesale markets for long-term sales”;⁴³ 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 . . . to buyers other than the utility to which the qualifying facility is interconnected”;⁴⁴ or (3) wholesale markets that have a similar competitive quality as the markets described above.⁴⁵

Thus, FERC is tasked with determining (1) which actual markets meet the requirements of the markets listed above, and (2) whether the QF has non-discriminatory access to that market.⁴⁶ If both factors

primary job of an RTO is to match electricity generation to the load requirement instantaneously in order to keep the supply and demand for electricity in balance. ISO/RTO COUNCIL, *THE VALUE OF INDEPENDENT REGIONAL GRID OPERATORS* 7 (2005). The operators will forecast load requirements and then schedule sufficient generation to meet that load, and also ensure that back-up generation is available in case demand rises unexpectedly or a power plant goes offline. *Id.* RTOs also operate day-ahead and real-time spot markets for wholesale electricity, which give electricity suppliers more options to meet demand for power at the lowest possible cost. *Id.*

⁴⁰ TOMAIN & CUDAHY, *supra* note 3, at 396.

⁴¹ Order No. 688, *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, 117 F.E.R.C. ¶ 61,078 at P 1 (Oct. 20, 2006) (to be codified at 18 C.F.R. pt. 292) [hereinafter Order No. 688].

⁴² Public Utility Regulatory Policies Act of 1978, Pub. L. No. 111-5, § 210(m)(1) (codified as amended at 16 U.S.C. 824a-3).

⁴³ § 210(m)(1)(A).

⁴⁴ § 210(m)(1)(B).

⁴⁵ § 210(m)(1)(C).

⁴⁶ Order No. 688, *supra* note 41, P 1.

are met, then a utility does not have to continue to purchase electricity from a QF nor enter into a new contract with a QF once the current contract expires. Congress's rationale for this rule is that as long as a QF has open access to the market, the mandatory purchase obligation is not necessary because the competitive market will stimulate QF development on its own.⁴⁷

PURPA section 210(m)(3) requires a utility seeking to be excused from its current purchase obligation to file an application with FERC that specifies how the QF that it is engaged with has access to one of the three types of wholesale markets.⁴⁸ FERC has ninety days after the filing date to provide notice to the affected parties, provide an opportunity for comment, and decide whether to approve the application and relieve the purchasing utility of its obligation.⁴⁹ If FERC approves a utility's application, the affected QF, a state agency, and other affected parties have the opportunity to reinstate the purchase obligation if the conditions allowing the discharge change.⁵⁰

In Order No. 688, FERC also determined that four particular markets (Midwest Independent Transmission System Operator, Inc. (Midwest ISO), PJM Interconnection, L.L.C. (PJM), ISO New England, Inc. (ISO-NE), and the New York Independent System Operator (NYISO)) met section 210(m)'s requirements for wholesale markets.⁵¹ Additionally, FERC determined that QFs with net generation capacity over twenty megawatts have a rebuttable presumption of nondiscriminatory access to the four listed markets.⁵² However, as mentioned previously, section 210(m)(3) requires utilities seeking relief from existing purchase obligations to file an application for relief with FERC (they are not automatically excused), and the affected QF has the opportunity to rebut the presumption of market access. But based on the provisions in section 210(m), most purchasing utilities will not have difficulty meeting the requirements for relief; thus, the opportunity to rebut the presumption does not provide much consolation for QFs.

⁴⁷ *Id.* P 6.

⁴⁸ Public Utility Regulatory Policies Act § 210(m)(3).

⁴⁹ § 210(m)(3).

⁵⁰ § 210(m)(4).

⁵¹ Order No. 688, *supra* note 41, P 8.

⁵² *Id.* P 9(B); *Major Qualifying Facility (QF) Orders*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/qual-fac/orders.asp> (last updated Feb. 3, 2012).

3. Section 210(m) Hurts Renewable Generation

The addition of section 210(m) to PURPA is detrimental to the goal of increasing the number of QFs entering the market and encouraging generation from a diversified mix of renewable sources. Removing the obligation to purchase a QF's electricity takes the "teeth" out of PURPA section 210 because at this point in time there is no incentive for a utility to purchase electricity from a renewable generator in excess of the mandated purchase requirement in its state's RPS.⁵³

The mandatory purchase requirement of QF-generated electricity was included in PURPA section 210 in order to give small renewable generators and cogeneration facilities a more level playing field in an electricity market that has long been dominated by traditional, fossil fuel-based generators. The rationale that a QF does not need the guaranteed purchase requirement if it has non-discriminatory access to wholesale markets is flawed. Even if a QF has unrestricted market access, what utility would choose to pay the higher price for electricity generated from renewable sources when the end product that they are purchasing—electricity—is the same? Unless the utility has a strong environmental conscience, it is unlikely to engage with QFs. The more likely scenario is that the utility will choose to build its own generation facility and employ the cheapest fuel source allowed under state law because investments in new generation earn the utility a rate of return. The result is a win-win situation for the utility—no requirement to purchase from QFs, and a higher rate of return for the utility—while the QF is left out in the cold.

QFs over twenty megawatts that operate within an RTO or ISO have struggled to defeat the rebuttable presumption of market access when brought before FERC by their mandatory purchasing utility.⁵⁴ One QF succeeded in defeating the rebuttable presumption by presenting very specific facts about the operating characteristics of its facility that prevented it from participating in the RTO's day-ahead and real-time energy markets without penalty.⁵⁵ FERC accepted this

⁵³ Moreover, the utility only has to purchase the amount required by the state RPS if that RPS is binding and not simply "goals."

⁵⁴ See *Va. Elec. and Power Co.*, 124 F.E.R.C. ¶ 61,045 (July 17, 2008).

⁵⁵ *New York State Elec. & Gas Corp. & Rochester Gas & Elec. Corp.*, 130 F.E.R.C. ¶ 61,216 at P 8, 20 (Mar. 18, 2010). New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E) filed an application pursuant to section 210(m) of PURPA and section 292.310 of FERC's regulations seeking to terminate

argument and found that the QF lacked nondiscriminatory access when its generation was contingent upon an intermittent source (i.e., steam from cogeneration) that made it impracticable to participate in day-ahead markets, and furthermore, if the QF did participate and failed to meet day-ahead commitments, it would be fined by the RTO, while other intermittent generators were exempt from the same fines and were also compensated for over-generation.⁵⁶

The lesson from this adjudication is that a successful rebuttal of a PURPA 210(m) challenge must be highly fact specific. Thus, a QF seeking to maintain its mandatory purchase status must demonstrate with specificity (1) the operating characteristics of its facility or energy source that prevent it from participating in the wholesale market, and (2) that it will be treated differently than other similar generators. Simply claiming a lack of access is not enough to overcome the presumption.⁵⁷ Therefore, it is very important that a QF be able to explain its own operations in the context of the RTO's market structure and market rules.

the obligation to enter into new power purchase obligations or contracts with QFs over twenty megawatts situated within the New York Independent System Operator, Inc. (NYISO). *Id.* P 1, 4. Cornell University was one of the affected QFs. *Id.* P 7–8. Cornell owned and operated a forty megawatt cogeneration facility in Ithaca, New York and was a self-certified QF. *Id.* Cornell claimed that the operational characteristics of its cogeneration facility, namely its steam load that is dependent on weather conditions, made its excess electrical output highly variable and unpredictable on a daily basis. *Id.* Thus, Cornell was prevented from participating in the NYISO wholesale market because the NYISO Market Service Tariff imposed penalties for undergeneration on generators with variable loads. *Id.* Moreover, under the same tariff, intermittent generators such as wind, landfill gas, and solar were exempted from the penalties, therefore, Cornell did not have non-discriminatory access. *Id.* Based on the specificity of Cornell's arguments, FERC concluded

[w]hile certain intermittent resources such as wind and solar facilities are exempted from penalties for under-generation and compensated for over-generation, this is not available to Cornell Given the high variability in its electric output due to its variable useful thermal output, and given that NYISO's markets tie participation to power offered into the market the day before, in conjunction with penalties for under-generation and no compensation for over-generation for QFs like Cornell, we conclude that Cornell is effectively denied nondiscriminatory access to NYISO's markets.

Id. P 20.

⁵⁶ *Id.* P 20.

⁵⁷ *Id.* P 21.

II

HOW DOES A RENEWABLE GENERATOR SELL ITS ELECTRICITY AT WHOLESALE?

This Part presents the advantages and disadvantages of the different approaches that renewable generators can take to sell the electricity they generate. The two primary approaches are to either obtain QF status or to gain market-based rate authority.

A. Option One: Become a QF

Despite some of the setbacks discussed above, there are still considerable benefits to being granted QF status by FERC; in particular, if the QF is less than twenty megawatts, then PURPA section 210(m)'s "rebuttable presumption" does not apply. The primary benefit of QF status is that QFs are exempt from complying with parts of the FPA, PURPA, and certain state laws that govern the rates and financial regulation of electric utilities.⁵⁸ Hence, many renewable electricity generators seek QF status in order to take advantage of the favorable regulatory treatment.

To become a QF, a facility must meet the QF requirements discussed in Part I Section B, which specified the sizes and sources that may qualify for QF status. Facilities with a maximum generation capacity of one megawatt or less are not required to file an application with FERC in order to claim QF status; however, they may seek Commission certification if they desire.⁵⁹

Owners of facilities that have a maximum generation capacity greater than one megawatt may attain QF status in one of two ways.⁶⁰ The first option is to become a self-certified QF. To do so, the facility owner or operator must submit a completed Form No. 556⁶¹ via

⁵⁸ Public Utility Regulatory Policies Act of 1978, Pub. L. No. 111-5, § 210(e) (codified as amended at 16 U.S.C. § 824a-3) (explaining that the exemption remains as long as it is needed to encourage cogeneration and small power production as determined by FERC).

⁵⁹ FERC Order No. 732 allows facilities with a maximum generation capacity of one megawatt or less to claim QF status without filing with the Commission. 18 C.F.R. § 292.203(d)(1) (2012).

⁶⁰ *How to Obtain QF Status for Your Facility*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/qual-fac/obtain.asp> (last updated Feb. 3, 2012).

⁶¹ Form No. 556 is available to download from FERC's website at <http://www.ferc.gov/industries/electric/gen-info/qual-fac/obtain.asp>.

FERC's eFiling system.⁶² Upon receipt of the form, FERC will issue a docket number so the applicant has a record of its filing and at this point the process is complete—the facility is a self-certified QF and will receive no further documentation from FERC.⁶³

The second option is to receive a Commission certification from FERC, which is often useful when carrying on negotiations for power purchase agreements. The applicant must complete a nineteen-page application that collects information about the location of the facility, the utilities that will transact with the facility, ownership and operation, sources used to generate electricity, the facility's capacity, a certification of compliance with size limitations and fuel limitations, EPA 2005 requirements, and information specific to cogeneration facilities.⁶⁴ After eFiling a complete Form No. 556 and paying the accompanying filing fee, the applicant can use FERC's online eLibrary to locate its docket number and application materials.⁶⁵ FERC will respond to the application within ninety days of filing to either grant or deny the application, or to toll the date required for issuing a decision on the application. However, if FERC has taken no action within ninety days of the original filing date or the date the application was amended (whichever is later), then the application is automatically granted and the applicant will be issued a Commission certification.⁶⁶

The last requirement for all filers, regardless of whether the applicant seeks self-certification or Commission certification, is to provide notice to all electric utilities that the facility plans to interconnect with, transmit, sell, or purchase electricity from; the state-level authority that will regulate the facility; and all of the utilities with which it will conduct business.⁶⁷ The Commission is responsible for publishing a description of the filing in the *Federal Register* to provide notice to the public.⁶⁸

⁶² *Self-Certification*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/qual-fac/self-cert.asp> (last updated Feb. 3, 2012).

⁶³ *Id.*

⁶⁴ *Application for Commission Certification*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/qual-fac/comm-cert.asp> (last updated Feb. 3, 2012).

⁶⁵ *Self-Certification*, *supra* note 62 (noting applicants can locate their information by performing a "New Dockets Search").

⁶⁶ *Application for Commission Certification*, *supra* note 64.

⁶⁷ *Notice Requirements*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/qual-fac/notice.asp> (last updated Feb. 3, 2012).

⁶⁸ *Id.*

B. Option Two: Obtain Market-Based Rate Authority

If a renewable electricity generator does not want to become a QF, or does not meet the specific requirements for QF status, then a second option for selling its electricity is to gain market-based rate authority from FERC. Market-based rate authority allows a seller that has been granted this authority to sell electricity into the wholesale market competitively, at a rate determined by the market, rather than restricting the seller to a cost-based rate.⁶⁹

A renewable generator may actually prefer market-based rate authority because it allows the generator to negotiate a power purchase agreement or standard contract that is based on the market price for the electricity and then lock that price into a long-term contract.⁷⁰ Moreover, although the transaction between a generator with market-based rate authority (the seller) and a purchasing utility (the buyer) is indeed a wholesale sale of electricity that falls under FERC's regulatory jurisdiction, FERC will assume that the rate agreed upon by the seller and purchaser is just and reasonable.⁷¹ Thus, unless someone petitions, FERC will honor the contract that the parties entered into without reviewing it. If FERC does not grant a seller market-based rate authority, that seller can only sell electricity at cost-based rates that are reviewed by FERC according to traditional cost-based ratemaking guidelines.⁷² The downside to the market-

⁶⁹ JAMES H. MCGREW, FERC: FEDERAL ENERGY REGULATORY COMMISSION 194 (2d ed. 2009).

⁷⁰ See *Avoided Costs (Incremental Costs)*, N.C. SUSTAINABLE ENERGY ASS'N, <http://energync.org/assets/files/AvoidedCosts.pdf> (last visited Mar. 16, 2013).

⁷¹ This assumption is based on the Mobile-Sierra Doctrine. The Mobile-Sierra Doctrine is the result of two landmark Supreme Court cases addressing the issue of contractually established rates and the ability to change or adjust those rates. See MCGREW, *supra* note 69, at 199–205. Neither the FPA nor the Natural Gas Act (NGA) specifies how FERC should regulate bilateral or multiparty contracts for ratemaking; the only guiding rule is that the rates must be “just and reasonable” (according to the FPA). *Id.* at 199. In 1956, the Supreme Court addressed this issue in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956). Together, the two cases created the Mobile-Sierra Doctrine, which provides that any freely-negotiated bilateral or multiparty contract for the wholesale sale of electricity is presumed to satisfy the FPA requirement of just and reasonableness. *Id.* at 201. However, if it can be shown that the contract threatens or harms the public interest, the presumption that the contract is just and reasonable is overcome, and FERC has the authority to review and revise it. *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1*, 128 S. Ct. 2733, 2756–57 (2008). Traditional grounds for invalidating a contract, such as fraud or duress, can also be used to contest the contract. *Id.* at 2746.

⁷² MCGREW, *supra* note 69, at 194.

based approach is that the generator selling its electricity must comply with FPA requirements (QFs are exempt in many ways) and specific FERC reporting requirements.

Additionally, gaining market-based rate authority can be a difficult hurdle for a renewable generator because of the criteria it must meet to gain approval from FERC.⁷³ The concern about granting market-based rate authority to sellers of electricity is based on the fact that electric utilities are monopolies with considerable power to abuse the market when left unregulated.⁷⁴ In fact, Part II of the FPA was enacted specifically to curtail the problem of market-based rates that had gotten out of hand because wholesale electricity sales were unregulated.⁷⁵ Essentially, unregulated electricity markets could not ensure that rates were “just and reasonable,” which is the standard for rates under the FPA.⁷⁶

Thus, historically, FERC would only grant market-based rate authority to sellers that were not vertically integrated (sellers that did not own both generation and transmission facilities) as a precaution to prevent monopolization and manipulation of the market.⁷⁷ However, over time FERC changed its position and allowed vertically integrated sellers or power marketers affiliated with vertically integrated sellers to receive market-based rate authority as long as the seller or its affiliates did not have, or could mitigate, market power in generation and transmission and could not erect other barriers to entry.⁷⁸ Additionally, the transmission provider was required to have an approved open-access transmission tariff on file with FERC.⁷⁹ The open-access transmission tariff ensured that utilities that owned or controlled transmission lines would allow nondiscriminatory access to those transmission lines and would “provide service to third parties comparable to service provided for their own sales.”⁸⁰ However, these

⁷³ *Electric Market-Based Rates*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/mbr.asp> (last updated Nov. 27, 2012).

⁷⁴ TOMAIN & CUDAHY, *supra* note 3, at 39.

⁷⁵ MCGREW, *supra* note 69, at 193.

⁷⁶ Federal Power Act of 1920, Pub. L. No. 109-58, § 205(a), 41 Stat. 1063 (2005) (codified as amended at 16 U.S.C. 824).

⁷⁷ MCGREW, *supra* note 69, at 194–95.

⁷⁸ *Id.* at 195–96. These requirements are laid out in *Heartland Energy Servs., Inc., et al.*, 68 F.E.R.C. ¶ 61,223 (1994) and FERC Order No. 888.

⁷⁹ *Id.* at 196 (required in FERC Order No. 888).

⁸⁰ *Id.* at 258. A tariff is simply a “compilation, either in book form or on electronic media, of all the effective rate schedules of a regulated entity together with a copy of each form of service agreement.” *Id.* at 260.

regulations did not prove to be sufficient—market-based sellers were not following FERC’s reporting requirements and FERC drastically neglected its duties of monitoring and enforcement.⁸¹

In response to serious manipulation of the electricity market, FERC reviewed its existing procedures, initiated rulemaking, solicited comments, and issued Order No. 697: Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services By Public Utilities.⁸² Order No. 697 and 18 C.F.R. Part 35, Subpart H contain the current requirements that a seller must meet in order to be granted market-based rate authority.⁸³ An applicant must establish that it and its affiliates meet the Commission’s standards for (1) horizontal market power and (2) vertical market power, in addition to proposing (3) a tariff containing all of the required provisions outlined by FERC.⁸⁴

A seller can meet the first two requirements by submitting a market power analysis that addresses whether or not it has horizontal and vertical market power.⁸⁵ Horizontal market power is determined by two market power screens: “a pivotal supplier analysis based on the annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis.”⁸⁶ If the seller passes the two market power screen tests, there is a rebuttable presumption that the seller lacks horizontal market power; if the seller fails the screen tests, then there is a rebuttable presumption that the seller has horizontal market power, and the seller will need to successfully rebut the presumption to move forward in the application process.⁸⁷

Vertical market power is determined based on a seller or its affiliate’s control over transmission facilities and wholesale energy markets.⁸⁸ If a seller or its affiliates “own, operate or control

⁸¹ *Id.* at 196. “The Commission’s experimentation with market-based rates produced unintended consequences in the form of market manipulation, gaming practices, and outright fraud. The California energy crisis and the collapse of Enron are the most notorious examples of the failure of the market-based sales experiment.” *Id.* This result was compounded by FERC’s severe neglect of monitoring and enforcement.

⁸² *Id.* at 197.

⁸³ *How do I Get Authorization?: What do I Include in My Application? What Requirements Apply?*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/mbr/authorization/app.asp> (last updated Nov. 27, 2012).

⁸⁴ 18 C.F.R. § 35.37 (2012).

⁸⁵ § 35.37.

⁸⁶ § 35.37(c)(1).

⁸⁷ § 35.37(c)(1)–(3).

⁸⁸ § 35.37(d).

transmission facilities, [then they] must have on file with the Commission an Open Access Transmission Tariff.”⁸⁹ Additionally, the seller must show that it lacks ownership or control over inputs to electric power production, such as interstate natural gas transportation, coal supply, and sites it plans to develop for electricity generation.⁹⁰ The seller must include this information in the application and also affirm that it has not, and will not, erect barriers to the relevant market.⁹¹

The third part of the application process is the seller’s proposed tariff. Section 205 of the FPA requires a seller seeking market-based rate authority to file an application with FERC.⁹² FERC requires that the application be submitted online using its electronic eTariff system.⁹³ The applicant must register using FERC’s website, follow the instructions on the website, and assemble the rest of the application, which includes a proposed market-based rate tariff.⁹⁴ The application includes a transmittal letter; contact information; a description of the kinds of services offered; a description of the applicant’s and its affiliates’ business activities; an explanation of how the applicant satisfies the vertical and horizontal market power screens; a request to be designated as either a Category 1 or Category 2 Seller and an accompanying explanation of how it meets the requirements of the desired category (18 C.F.R. § 35.36(a)); requests for waivers or authorizations; an eTariff meeting the requirements of Order No. 697 and No. 697-A; and a two-part appendix of all generation or transmission assets, natural gas intrastate pipelines, and gas storage facilities owned or controlled by the applicant.⁹⁵ Some of these requirements are discussed in depth below.

A required component of the application is to determine if the seller is a Category 1 Seller or a Category 2 Seller. A seller is defined as “any person that has authorization to . . . engage in sales for resale of electric energy, capacity or ancillary services at market-based rates

⁸⁹ § 35.37(d) (§ 35.28 describes the Open Access Transmission Tariff).

⁹⁰ § 35.37(e).

⁹¹ § 35.37(e).

⁹² *How do I Get Authorization?: What do I Include in My Application? What Requirements Apply?*, *supra* note 83.

⁹³ *Id.*

⁹⁴ *Id.*; *How do I Get Authorization?: Step by Step Guide to Filing Your Application in the eTariff System*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/mbr/authorization/guide.asp> (last updated Aug. 7, 2013).

⁹⁵ *How do I Get Authorization?: Step by Step Guide*, *supra* note 94.

under section 205 of the Federal Power Act.”⁹⁶ Category 1 Sellers are defined as “wholesale power marketers and wholesale power producers that own or control 500 megawatts or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid.”⁹⁷ Additionally, Category 1 Sellers cannot be affiliated with others who might pose vertical market power issues, such as someone who owns or controls transmission in the same region that the seller generates electricity in, or a franchised public utility in the same region.⁹⁸ Category 2 Sellers are defined as “any Sellers not in Category 1.”⁹⁹

Additionally, the seller must propose a market-based rate tariff that will govern its wholesale sales at market-based rates if FERC should approve the application. FERC provides a sample tariff on its webpage. The sample begins with a clause listing the availability of the seller’s electricity for purchase and a clause stating that the rates shall be established by agreement between the seller and the purchaser.¹⁰⁰ However, the tariff must contain specific requirements to be considered by FERC: (1) the proposed tariff must contain two provisions copied without modification from FERC’s example¹⁰¹ that assure compliance with FERC regulations and list limitations on a seller’s market-based rate authority, (2) the seller must list whether it is a Category 1 or Category 2 Seller for every region in which it operates,¹⁰² and (3) each tariff must be submitted through the eTariff system.¹⁰³ The Commission also requires the inclusion of additional unmodified provisions in the eTariff if they apply to the particular

⁹⁶ 18 C.F.R. § 35.36(a)(1) (2012).

⁹⁷ § 35.36(a)(2).

⁹⁸ *Id.*

⁹⁹ § 35.36(a)(3).

¹⁰⁰ *Market-Based Rate Tariff*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/mbr/tariff.asp> (last updated Nov. 27, 2012).

¹⁰¹ Order No. 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services By Public Utilities*, 119 F.E.R.C. ¶ 61,295 at P 915-916 (June 21, 2007) (requiring the inclusion of two provisions, which can be found on FERC’s website. See *How Do I Get Authorization?: Ancillary Services and Required Tariff Provisions*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/mbr/authorization/provision.asp> (last updated Aug. 27, 2013).

¹⁰² Order No. 697-A, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services By Public Utilities*, 123 F.E.R.C. ¶ 61,055 at P 391 (Apr. 21, 2008).

¹⁰³ Order No. 714, *Electronic Tariff Filings*, 124 F.E.R.C. ¶ 61,270 (Sept. 19, 2008).

seller.¹⁰⁴ Whether the seller falls under Category 1 or Category 2 affects the schedule of the future monitoring process by FERC. FERC reviews sellers in each of its six regions every three years, known as the “Triennial Reviews.” FERC requires all Category 2 Sellers that have achieved market-based rate authority to file a market power analysis for the particular region that they operate in based on the regional review schedule outlined in Order No. 697-A.¹⁰⁵

III

STATES HAVE THE POWER TO MOVE FROM AVOIDED COSTS TO FEED-IN TARIFFS

The previous two Parts explained the federal regulation of wholesale sales of electricity and the preemption obstacle states encounter, as well as the two different routes a renewable generator can take to sell its electricity. This final Part discuss two very important FERC Orders that chipped away at federal preemption and revealed a legal solution that increases a state’s ability to affect the avoided cost for renewables. Specifically, FERC’s October 21, 2010 Order clarified that if a state requires utilities to obtain electricity from a very specific set of sources, then the state can set the avoided cost for each source at the lowest cost to obtain that specific source. In other words, with careful construction of a renewable energy mandate (or binding RPS), a state can essentially create a feed-in tariff for the renewable sources that they require. Below is a detailed explanation of how a state can leap from a standard avoided cost calculation to the ability to structure a feed-in tariff for renewable sources.

A. The California Public Utilities Commission Tests Its Boundaries

The California Public Utilities Commission (CPUC) tested the boundaries of its authority to affect wholesale sales when it implemented Assembly Bill 1613 (AB 1613) which “amended the California Public Utilities Code to require ‘electrical corporations’ in California . . . to offer to purchase, at a price to be set by the CPUC, electricity that is generated by certain CHP generators and delivered

¹⁰⁴ The eight additional provisions that may apply, depending on the seller, can be found on FERC’s website. See *How do I Get Authorization?: Step by Step Guide*, *supra* note 94.

¹⁰⁵ *Triennial Reviews—When to File*, FED. ENERGY REG. COMMISSION, <http://www.ferc.gov/industries/electric/gen-info/mbr/triennial/when.asp> (last updated Nov. 27, 2012).

to the grid.”¹⁰⁶ The CHP generators referred to in AB 1613 are combined heat and power generators (known as “cogenerators” under PURPA) that do not generate over twenty megawatts of electricity and must meet specific efficiency and emission standards set by the CPUC.¹⁰⁷ Some of the large utilities affected by this decision (later referred to as the “Joint Utilities”), including Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company, did not like the CPUC’s implementation of AB 1613 and petitioned FERC, claiming that the CPUC did not have the authority to set wholesale rates for CHP generators because it is preempted by the FPA.¹⁰⁸ The CPUC then requested that FERC find that the decision to “require California utilities to offer a certain price to combined heat and power (CHP) generating facilities of twenty megawatts or less that meet energy efficiency and environmental compliance requirements” is not preempted by the FPA, PURPA, or FERC regulations.¹⁰⁹

FERC issued a response to the CPUC’s request in its July 15, 2010 Order¹¹⁰ concluding that “a state commission may, pursuant to PURPA, determine avoided cost rates for qualifying facilities”¹¹¹ and:

[T]he CPUC’s AB 1613 feed-in tariff would *not* be preempted by the FPA, PURPA, or Commission’s regulations as long as: (1) the CHP generators from which the CPUC is requiring the Joint Utilities to purchase energy and capacity are QFs pursuant to PURPA; and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility.¹¹²

Based on this language, the July 15, 2010 Order was only a partial victory for the CPUC because, although FERC said the CPUC could proceed with its new CHP program as long as it was implemented within the bounds of PURPA, the rate established by the CPUC for CHP electricity could still not exceed the avoided cost of the purchasing utility. In October 2010, the CPUC asked FERC for

¹⁰⁶ *Cal. Pub. Utilities Comm’n*, 133 F.E.R.C. ¶ 61,059 at P 4 (Oct. 21, 2010) (citing CPUC May 4, 2010 Petition at 2–3).

¹⁰⁷ *See id.* P 3.

¹⁰⁸ *Id.*

¹⁰⁹ *Id.* CPUC asked FERC to rule that § 205 and § 206 of the FPA and § 210 of PURPA did not preempt the CPUC’s AB 1613.

¹¹⁰ *Cal. Pub. Utilities Comm’n*, 132 F.E.R.C. ¶ 61,047 (July 15, 2010).

¹¹¹ *Cal. Pub. Utilities Comm’n*, *supra* note 106, P 5.

¹¹² *Id.*

clarification. FERC handed down its October 21, 2010 Order, which proved to be a huge victory for states and renewables.

B. FERC's October 21, 2010 Order

In FERC's October 21, 2010 Order, the CPUC requested clarification on its authority to set avoided cost, specifically pertaining to its own assertions that:

(1) the CPUC can require retail utilities to consider different factors in the avoided cost calculation in order to promote development of more efficient CHP facilities; and (2) "full avoided cost" need not be the lowest possible avoided cost and can properly take into account real limitations on "alternate" sources of energy imposed by state law.¹¹³

The CPUC claimed that PURPA's stated purposes of "increas[ing] the use of cogeneration and small power production facilities and to reduce reliance on fossil fuels"¹¹⁴ was consistent with its argument to offer a higher avoided cost rate to more efficient generators.

FERC agreed with the CPUC, stating, "the concept of a multi-tiered avoided cost rate structure can be consistent with the avoided cost rate requirements set forth in PURPA and in our regulations."¹¹⁵ Moreover, "where 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 requirement."¹¹⁶ This language is incredibly empowering for states. It means that if a state mandates that a utility purchase electricity from a specific renewable source, then the avoided cost that the utility has to pay can be set at the lowest cost of obtaining that specific renewable source.¹¹⁷ In other words, the renewable generator will actually get paid a rate that covers the cost of generating the electricity! For example, in terms of the CPUC's CHP program, if the state mandates that Utility A purchase twenty percent of its electricity from CHP facilities that generate twenty megawatts or less and meet specific energy efficiency and compliance requirements, then the state can set avoided cost at the lowest cost to generate electricity meeting all of those specific characteristics.

¹¹³ *Id.* P 7.

¹¹⁴ *Id.* P 13.

¹¹⁵ *Id.* P 26.

¹¹⁶ *Id.* P 27, 29.

¹¹⁷ *See id.* P 29, 31.

FERC's October 21, 2010 Order allows states to greatly expand their base of renewable sources as long as they provide specific requirements detailing the mix of renewables that must make up the state's energy base in the form of a detailed RPS or other mandate. As a result, utilities are prevented from continuing to only purchase the cheapest renewable sources (or none at all, depending on the state's RPS requirements). This is an incredibly important shift because it gets other renewables that may be more expensive onto the grid, which will drive down their cost and allow a more diverse mix of renewables to fulfill our energy needs.

C. FERC's January 20, 2011 Order

The Joint Utilities were not happy with the October 21, 2010 Order because it affirmed that states do in fact have the authority under PURPA to require utilities to purchase renewable energy required by their RPS at the actual cost of producing that energy, so they requested a rehearing. FERC denied the request for a rehearing in its January 20, 2011 Order, ruling boldly in favor of state authority to set rates for renewables by affirming that "states have the authority to dictate the generation resources from which utilities may procure electric energy"¹¹⁸ and "[a]s explained in the Clarification Order, where a state requires a utility to procure 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 requirement."¹¹⁹

D. Feed-In Tariffs Under PURPA

FERC's October 21, 2010 Order and January 20, 2011 Order are major victories for state action on renewables because they have essentially opened the door for states to design feed-in tariffs for renewable sources. Currently, there is no officially recognized definition of a feed-in tariff, but feed-in tariffs typically require a utility to purchase electricity (generated from renewable sources) at a rate that covers the cost of generation, or even better, allows the renewable generator to make a profit and enter into a long-term

¹¹⁸ *Cal. Pub. Utilities Comm'n*, 134 F.E.R.C. ¶ 61,044 at P 30 (Jan. 20, 2011).

¹¹⁹ *Id.*

contract.¹²⁰ The National Renewable Energy Laboratory provides a working definition of a feed-in tariff as a program “which obligates an electric distribution utility to purchase electricity from an eligible renewable energy seller at specified prices (set sufficiently high to attract to the state the types and quantities of renewable energy desired by the state) for a specified duration.”¹²¹

The next question when designing a feed-in tariff is, which pricing model will achieve the desired results? There are several options, including a “cost-based” model, where the generator recovers the cost of generation and a reasonable profit; a “market-based” model, where the price is decided after examining competing prices among similar operations; and a “value-based” model, where the value placed by citizens on the benefits of a cleaner environment or a diverse source of generation is reflected in the price of the electricity.¹²²

CONCLUSION

For decades the Federal Power Act severely limited a state’s ability to increase the percentage of electricity in the market generated from renewable sources. Although the passage of PURPA section 210 greatly aided renewable generators by requiring utilities to purchase QF-generated electricity, the avoided cost provision of the Act failed to compensate the renewable generator for the full cost of producing its clean electricity. Additionally, EAct 2005 blunted PURPA’s effectiveness. Despite these continued setbacks, a state’s ability to influence the wholesale price for renewable energy grew by leaps and bounds with the October 21, 2010 and January 20, 2011 FERC Orders, which clarified that states *can* legally design feed-in tariffs for renewable sources within the bounds of PURPA.

As a result of these FERC decisions, states across the country should feel empowered to create “tiered-systems” where separate avoided costs for each type of renewable source in the tier can be established. To achieve this, states must be incredibly diligent about designing mandates for renewables (either through an RPS or other mandate) that clearly indicate the specific quantity and kind of renewables, along with any desired characteristics, that a utility must

¹²⁰ SCOTT HEMPLING ET AL., NAT’L RENEWABLE ENERGY LAB., RENEWABLE ENERGY PRICES IN STATE-LEVEL FEED-IN TARIFFS: FEDERAL LAW CONSTRAINTS AND POSSIBLE SOLUTIONS iv (2010).

¹²¹ *Id.*

¹²² *Id.* at 44. Disagreement exists as to whether the three models proposed are all “true” feed-in tariffs. The cost-based model is the most widely accepted approach.

purchase. States should take advantage of this creative solution because it does not require any changes to current law.¹²³ But much of the momentum lies in the hands of state legislatures to carefully design tiered-systems and pass them into law. The legal solution for increasing and diversifying the amount of electricity generated from clean, renewable resources lies waiting. Now is the time to act.

¹²³ This Comment advocates for the use of feed-in tariffs within the bounds of PURPA; however, other routes exist to achieve the same goal. Three other potential routes include: (1) developing the REC system; (2) lobbying Congress for a legislative amendment to the FPA; and (3) lobbying FERC to amend avoided cost factors.

