

SUBSIDIES, CLIMATE CHANGE, ELECTRIC MARKETS AND THE FERC

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Synopsis: The electric utility industry has long endured an uneasy mix of competition and regulation. Some regions have embraced competitive markets, retail access, and generation divestiture; others have retained vertical integration and traditional regulation; and others fall somewhere in the middle, with a mix of traditional retail regulation and organized wholesale markets. The challenges presented by this mix of regulation and competition are substantial, but in the last few years an even more vexing challenge has emerged: increasing government subsidies designed to dictate particular market outcomes. Many, but not all, of these subsidies are driven by efforts to address climate change. This article addresses the challenges these subsidies present to the Federal Energy Regulatory Commission (FERC) when regulating wholesale markets. The article discusses both the FERC’s legal authority to protect markets from the adverse effect of subsidies and its political discretion to choose which issues merit attention.

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I. INTRODUCTION

The domestic electric utility industry long endured an uneasy mix of regulation and competition. Some regions of the country have fully restructured, embracing generation divestiture, retail access and Regional Transmission Organizations (RTOs), whereas others have retained vertical integration,

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traditional retail regulation, and bilateral wholesale markets. Still others fall somewhere in the middle, with traditional regulation at the retail level and organized markets administered by an RTO at the wholesale level. Even within fully restructured markets there is a tension between wholesale market prices that vary each hour based on competitive bids and regulated retail prices that remain fixed for most customers.

If the challenges presented by this mix of competition and regulation were not hard enough, the last few years have introduced another one: government intervention in restructured wholesale markets through subsidies designed to achieve particular market outcomes. Many of these interventions are designed to address climate change by increasing the development of renewable resources through renewable energy mandates, production tax credits, and net metering programs. But these are not the only interventions. There have been recurring efforts by states to subsidize entry (or retention) of conventional generation resources in an effort to lower prices in capacity markets.

The late Alfred Kahn often reminded us the choice is not between perfect competition and perfect regulation, but rather an imperfect version of each.¹ When reintroducing Kahn's classic, *The Economics of Regulation*, Paul Joskow observed that the onset of partial deregulation in several industries had created the potential for "the worst of both possible worlds."² We now increasingly face that prospect in organized electric markets. Subsidies are creating a toxic mix of imperfect competition and imperfect regulation working directly at cross-purposes with each other. Reasonable minds can differ as to the level of resulting harm, but it is hard to argue the harm is not real and growing.

The harm can arise in several ways. There are unintended consequences. Renewable subsidies designed to combat climate change are contributing to the potential retirement of nuclear power plants, which represent the nation's largest source of carbon-free energy.³ There are cost shifts among various customer groups. Net metering subsidies create a large wealth transfer from customers without rooftop solar, particularly lower income customers, to those with rooftop solar.⁴ There are also distorted investment incentives. Subsidies for new

1. 2 ALFRED E. KAHN, *THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS* 324-329 (MIT 1988).

2. 1 ALFRED E. KAHN, *THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS* xxxv (MIT 1988). Paul Joskow has echoed this point, calling for regulation that balances "the cost of market imperfections" against "the cost of regulatory imperfections." PAUL JOSKOW, *MARKET IMPERFECTIONS VERSUS REGULATORY IMPERFECTIONS* 4 (MIT 2010); *see also id.* at 6:

Few if any markets are perfect in the sense that they satisfy the assumptions underlying textbook models of perfect competition or yield the performance associated with these textbook models. Market imperfections are the norm not the exception. . . . However, the fact that one can identify one or more market imperfections does not necessarily make a case for imposing government regulations on the relevant market unless one believes in the existence of a benevolent, costless, and perfectly informed regulator

3. *International Nuclear Energy Policy and Cooperation*, ENERGY.GOV, <http://www.energy.gov/ne/nuclear-reactor-technologies/international-nuclear-energy-policy-and-cooperation> (last visited Sept. 11, 2014).

4. David B. Raskin, *The Regulatory Challenge of Distributed Generation*, 4 HARV. BUS. L. REV. ONLINE 38, 42 (2013); California Net Energy Metering (NEM) Draft Cost-Effectiveness Evaluation (Ca. Pub.

generation suppress the prices paid by existing generators, contributing to more retirements and, in turn, more subsidies to maintain resource adequacy.⁵ There are also distorted incentives due to the fact the same resource can be paid differently depending on whether it is located behind or ahead of the meter.

To be sure, there is a competing view—namely, competitive markets are not functioning perfectly, so regulation should fill the gaps even if it does not fill them perfectly. There is merit to this view in the abstract: a fundamental premise of regulation, after all, is to remedy market failures. But regulation has not proven particularly adept at the task currently being asked of it: picking winners and losers among resource types and technologies. This is not because regulators have no capable analysts; rather, it is because no one, either in government or private industry, can predict the future with precision. Thus, the real choice is not over who has the best crystal ball, but rather who bears the risk of loss—ratepayers or investors—when the crystal ball fails. The example of the Public Utility Regulatory Policies Act of 1978 (PURPA) is useful in this regard.⁶ The statute was a success in reducing barriers to entry by new entrants and new technologies, but its aggressive implementation by certain states—driven in part by long-term fuel-price predictions proved inaccurate—created billions in over-market costs borne by customers.⁷ Those over-market costs, when coupled with nuclear plant cost overruns, led many states to embrace retail competition and organized wholesale markets in the 1990s. Yet we have now come nearly full circle by steadily moving away from competitive market outcomes in favor of resource-specific subsidies.⁸

Reasonable minds can differ on the degree to which the current regulatory interventions carry this risk of repeating history, but however one answers that question, the Federal Energy Regulatory Commission (FERC) is left with the unenviable task of maintaining the integrity of competitive wholesale electric markets in the face of these interventions. What can or should the FERC do about all of this? In a perfect world, the answers to both the “can” and “should” questions would be the same, but in a political economy the answers are rarely the same. The FERC can pick only so many battles with the states regardless of the scope of its legal authority, much less with Congress. The unglamorous history of Standard Market Design is one example of that political reality.⁹

With respect to what the FERC can do, the article concludes the FERC has ample authority to protect competitive wholesale markets from the adverse effect

Utils. Comm’n, Sept. 26, 2013), available at <http://www.cpuc.ca.gov/NR/rdonlyres/BD9EAD36-7648-430B-A692-8760FA186861/0/CPUCNEMDraftReport92613.pdf>.

5. CONT’L ECONS., STATE SUBSIDIZATION OF ELECTRIC GENERATING PLANTS AND THE THREAT TO WHOLESALE ELECTRIC COMPETITION 4-5, 7 (2012).

6. Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of 15, 16, 42, and 43 U.S.C.) [hereinafter PURPA].

7. CONT’L ECONS., *supra* note 5, at 5, 7-8.

8. *Id.* at 5, 7.

9. In the aftermath of the California crisis in 2002, the FERC proposed a Standard Market Design rule that would have mandated participation in organized wholesale electric markets. The political opposition in Congress and by several regions led the Commission to rescind the proposal. Order Terminating Proceeding, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM01-12-000 (FERC issued July 19, 2005).

of most subsidies; therefore, the harder question is what the FERC should do. With respect to that question, the article offers three general principles to help guide the use of political discretion: (i) the FERC should prioritize its agenda to address the subsidies causing the most harm; (ii) when the FERC decides to act, it should tailor its remedies, as much as practicable, to protect the market, not individual competitors; and (iii) the FERC should tailor those remedies in a manner that does not impinge unnecessarily on state policies with respect to resource mix. These three principles are admittedly not easy to satisfy because of the inherent tension among them.

Tangled up in these three principles is the sensitive question of whether intervening to protect markets from subsidies means being hostile toward efforts to combat climate change. Here too, reasonable minds can differ, but the article contends the two are not one and the same. Competitive markets are essential to the development of clean energy resources because they provide the geographic scope and transparent prices necessary to integrate those resources into the supply mix. The objective of strengthening competitive markets is therefore consistent, not in conflict, with removing barriers to the development of clean energy technologies. In fact, one prevalent subsidy discussed here is out-of-market support payments to conventional generation, which distorts market signals for all resources, including renewable energy and demand response. Moreover, the FERC has also acted on multiple occasions to reduce barriers to integrating renewable resources using authority to remedy undue discrimination. These reforms highlight a critical distinction: the FERC's charge is to remedy undue discrimination, not to create its own preferences (subsidies).

Therein lies much of the rub of the debate over the FERC's role in addressing climate change. Many in the environmental community argue the absence of a national carbon policy gives carbon-intensive resources a competitive advantage by failing to put a price on their emissions. This, in their view, means that wholesale market policies, which are fuel-neutral, serve to perpetuate this unfair advantage. By contrast, the predominant view held by the FERC's leadership across multiple administrations, both Democratic and Republican, is that the FERC is a fuel-neutral agency and, therefore, does not pick winners and losers by choosing sides in the climate change debate. The author shares this latter view. This does not mean the FERC cannot accommodate carbon regulation in wholesale market design. For example, when California created a cap-and-trade program for greenhouse gas emissions, the FERC approved changes in wholesale market design which accommodated it. But that is very different from the FERC creating greenhouse gas policy by imposing its own price on carbon emissions by wholesale sellers. Such an action would constitute a jurisdictional bridge too far irrespective of whether the underlying normative concern—that the nation should take more aggressive action to address climate change—is deemed correct or not.

II. BACKGROUND ON SUBSIDIES AND MARKETS

Competitive markets are critical to the integration of renewable resources, demand response, and distributed generation. The markets provide the geographic scope to integrate large amounts of renewable resources and the market signals to

attract and integrate new technologies in an efficient manner.¹⁰ Yet these markets are increasingly challenged by the very subsidies designed to support these green technologies. The markets are also increasingly challenged by out-of-market payments to conventional generation to subsidize entry into (or deter exit from) capacity markets. This section provides a relatively brief overview of several forms of subsidy currently affecting competitive electricity markets.

A. *Definitional Problems: What is a “Subsidy”?*

At the outset, it is important to define “subsidy,” an exercise that is both easy and hard. The definitional task is easy in the sense subsidies are commonly defined quite broadly to include “any form of preferred treatment granted to consumers or producers by a government” (a common definition in the international trade context).¹¹ As applied to power generation, this definition would include a broad array of government interventions, including government-funded research and development, tax incentives and preferences, loan guarantees, renewable mandates, and consumer-side subsidies (e.g., for net metering or demand response).¹²

The hard part has two components. First, defining subsidy to include all government interventions leaves out an important category: it “does not include the externalities associated with electricity generation,”¹³ an important omission in the context of the climate change debate. An environmentalist would argue renewable energy mandates are simply an attempt to counteract the *implicit* subsidy long provided to fossil fuel generation given the absence of carbon regulation. The second hard part is related: the normative debate over which subsidies are “good” or “bad.” For example, is government-funded research and development an efficient response to a market failure or an inefficient handout to the industry that lobbied for it?¹⁴ The same is true for loan guarantees: do they remedy a true failure in the financial markets or are they just an inefficient taxpayer-funded subsidy?

10. See generally William W. Hogan, *Electricity Wholesale Market Design in a Low Carbon Future* (Draft for volume on Harnessing Renewable Energy, Jan. 23, 2010), available at http://www.hks.harvard.edu/fs/whogan/Hogan_Market_Design_012310.pdf; N. AM. ELEC. RELIABILITY CORP. & CAL. INDEP. SYS. OPERATOR CORP., 2013 SPECIAL RELIABILITY ASSESSMENT: MAINTAINING BULK POWER SYSTEM RELIABILITY WHILE INTEGRATING VARIABLE ENERGY RESOURCES—CAISO APPROACH (2013) [hereinafter JOINT CAISO-NERC SPECIAL RELIABILITY ASSESSMENT]; PJM RENEWABLE INTEGRATION STUDY, TASK FORCE REPORT: REVIEW OF INDUSTRY PRACTICE AND EXPERIENCE IN THE INTEGRATION OF WIND AND SOLAR GENERATION, EXETER ASSOCS. & GE ENERGY (2012); PHILLIP BROWN, U.S. RENEWABLE ELECTRICITY: HOW DOES WIND GENERATION IMPACT COMPETITIVE POWER MARKETS, CONG. RESEARCH SERV. (2012).

11. LUCY KITSON ET AL., SUBSIDIES AND EXTERNAL COSTS IN ELECTRIC POWER GENERATION: A COMPARATIVE REVIEW OF ESTIMATES 6, INT’L INST. FOR SUSTAINABLE DEV. (2011).

12. *Id.*

13. *Id.*

14. See generally Alan O. Sykes, *The Economics of WTO Rules on Subsidies and Countervailing Measures* 6 (Chicago: John M. Olin Law & Econ. Working Paper No. 186, 2d Series, May 2003), available at http://chicagounbound.uchicago.edu/cgi/viewcontent.cgi?article=1515&context=law_and_economics (discussing, among other things, situations in which government funded research and development may be socially beneficial).

Distinguishing between “good” and “bad” subsidies is particularly important to the climate change debate. Many of the subsidies discussed herein—including renewable energy mandates and production tax credits—represent second-best policy responses to the political infeasibility of first-best policy choices, such as a nationwide cap-and-trade program or carbon tax. The author has no quarrel with the underlying intent of these second-best programs—to address climate change—but the *manner* in which they do so matters. A well-designed carbon tax or cap-and-trade program can efficiently regulate carbon without providing preferences (subsidies) to particular generation types, whereas second-best choices typically pick winners and losers (e.g., providing subsidies to wind and solar, but excluding other carbon-free sources such as nuclear or hydropower). Picking winners and losers “distort[s] resource allocation by diverting resources from higher valued to lower valued uses” or “[p]ut slightly differently, . . . distort[s] comparative advantage and produce a less efficient global division of labor, leading to lower economic welfare.”¹⁵

The article now turns to a discussion of four general classes of subsidies: (i) subsidies to incentivize entry into (or deter exit from) capacity markets; (ii) production-related subsidies affecting dispatch in energy markets; (iii) subsidies incentivizing distributed generation; and (iv) subsidies governed by the continued implementation of PURPA.

B. Capacity Markets

Capacity markets are the most controversial element of market design, with criticism directed at them on a continuous basis from virtually all sides.¹⁶ They continue to survive, however, because no one has yet implemented a better mousetrap for maintaining reliability in fully-restructured markets. The primary alternative is to remove or raise caps on energy and operating reserve prices during times of scarcity, but there are political challenges to doing so.¹⁷

The most common form of subsidy affecting capacity markets is state-supported, out-of-market payments for new resources that depress prices to existing resources (which in turn can make those subsidy payments economical for some customers in the short run). When merchant generators complained this behavior was akin to the exercise of monopsony power, the RTOs and their independent market monitors generally agreed. For example, Joseph Bowring,

15. *Id.* at 2.

16. Consumer groups argue they provide windfall profits to existing generators; state regulators argue they impinge on their resource planning prerogatives. Generators argue they have so many flaws they do not achieve their primary purpose of attracting new generation or forestalling retirements. Nicholas Sakelaris, *Industry Group Proposes Alternative to Capacity Market*, DALL. BUS. J. (Nov. 25, 2013 11:45 AM), <http://www.bizjournals.com/dallas/news/2013/11/25/industry-group-proposes-alternative-to.html?page=all>; *State Regulators Call for Capacity Market Changes*, RTO INSIDER (July 1, 2014), <http://www.rtoinsider.com/capacity-market-changes/>.

17. Hogan, *supra* note 10, at 13-15. See also William W. Hogan, *Electricity Scarcity Pricing through Operating Reserves* (Draft, Apr. 25, 2013), available at http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&cad=rja&uact=8&ved=0CC0QFjAB&url=http%3A%2F%2Fwww.hks.harvard.edu%2F%2Fwhogan%2FHogan_ORDC_042513.pdf&ei=eFkSVMytBpSdygSfxoC4CA&usg=AFQjCNGvNjeN1FgMHTHlEWkZjQJb15MKMg&bvm=bv.75097201,d.aWw.

PJM Interconnection's market monitor who is no apologist for generator interests, argued as follows when addressing the effects of certain New Jersey subsidies:

The New Jersey legislation would, if implemented, suppress the price of capacity in New Jersey and elsewhere in PJM. Whether intentional or not, this exercise of monopsony market power on behalf of New Jersey customers is short sighted, unlikely to reduce capacity payments by New Jersey customers in the long run and constitutes an intervention into the PJM capacity markets that is not consistent with a competitive outcome. *The New Jersey approach, if implemented, puts the entire capacity market at risk.*¹⁸

In a string of cases arising in each Eastern RTO, the FERC generally agreed with these concerns and adopted minimum offer price rules (MOPR) to protect against bids skewing the market,¹⁹ finding MOPRs “serve[] a critical function to ensure that wholesale prices are just and reasonable and . . . elicit new entry when new capacity is needed.”²⁰ With respect to the resulting conflict with state policy, the FERC held its “intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources,” but “[w]e are forced to act . . . when subsidized entry supported by one state’s or locality’s policies has the effect of disrupting the competitive price signals that [the region] as a whole, including other states, rely on to attract sufficient capacity.”²¹ The states strongly objected to this assertion of jurisdiction to mitigate bids affected by subsidies, but the Third Circuit Court of Appeals has affirmed the Commission’s jurisdiction to impose such mitigation.²² Both the Third Circuit and Fourth Circuit have also held that certain state subsidy payments (including the New Jersey program) are preempted by the Federal Power Act.²³

The issue has also arisen whether renewable resources should be exempt from these mitigation rules because they serve public policy goals other than price suppression. One market (PJM) exempts renewable resources from such mitigation and the New England states sought a similar exemption for renewable resources.²⁴ The FERC, in a 3-2 split decision, rejected the states’ request because the potential harm to the New England market exceeded that of the larger PJM market.²⁵ Commissioner (now acting Chair) LaFleur wrote separately to underscore the resulting dilemma posed by the states:

I believe that buyer-side market power proceedings present some of the most difficult issues we face at the Commission. These proceedings require the Commission to

18. Comments from the Independent Market Monitor for PJM, *Power Providers Grp. v. PJM Interconnection, L.L.C.*, at 2, Docket No. EL11-20-000 (Mar. 4, 2011) (emphasis added). Even the market monitor in the Midwest region, which has not been fully structured, has supported the use of a minimum offer pricing rule to prevent subsidies from skewing the capacity market. *Midwest Independent Transmission System Operator, Inc.*, 139 F.E.R.C. ¶ 61,199 at P 6 (2012).

19. *PJM Interconnection, L.L.C.*, 137 F.E.R.C. ¶ 61,145 (2011); *ISO New England, Inc.*, 135 F.E.R.C. ¶ 61,029 (2011) at P 66 (2011).

20. 137 F.E.R.C. ¶ 61,145 at P 2.

21. *Id.* at P 3.

22. *New Jersey Bd. of Pub. Util. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

23. *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467 (4th Cir. 2014); *PPL EnergyPlus, LLC v. Solomon*, No. 13-4330, 2014 WL 4454999 (3d Cir. Sept. 11, 2014).

24. *New England States Comm’n on Elec. v. ISO New England, Inc.*, 142 F.E.R.C. ¶ 61,108 at PP 11-12 (2013).

25. *Id.* at PP 35-36.

reconcile important regulatory objectives that are fundamentally in tension. On the one hand, states have the unquestioned right to make policy choices through the subsidization of capacity. On the other hand, as the regulator of that market, this Commission has the right—and indeed the responsibility—to assure that capacity bid into the FCM is priced in such a way as to assure that the FCM fulfills its purpose of supporting long-term reliability.²⁶

One year later, however, the Commission reversed course and approved a similar proposal from the New England Independent System Operator (ISO) made in conjunction with other capacity market reforms (e.g., implementation of a sloped demand curve).²⁷

More recently, these disputes have spread to subsidies to forestall generation retirement. Due to a range of factors, including low natural gas prices, increasing environmental regulations, and renewable energy subsidies, a broad range of existing generation assets are facing potential retirement decisions,²⁸ which in turn can create state concerns with respect to price increases and reliability. One current locus of this dispute is in New York, where the New York generator coalition has brought a complaint alleging the State is attempting to prop-up uneconomic generators with subsidy payments financed through price suppression.²⁹ The case remains pending with the FERC.

C. Energy Markets

Capacity markets are not the only market buffeted by subsidies. There are several forms of energy market subsidy causing concerns, two of which have drawn the most attention: the federal production tax credit and renewable energy credits created by various state mandates. Both apply (with some exceptions) to the actual production of energy of qualifying renewable resources, and thus, directly affect energy market prices. These subsidies have two related effects: first, they encourage the construction of resources with zero fuel costs, which lowers energy prices by altering the supply stack of resources competing in the market, and second, the subsidies allow those new resources to lower their energy bids even further to reflect the production-related subsidies.

The adverse effect of production-related subsidies is an empirical question has produced a sharp debate, particularly with respect to the situation when energy prices turn negative. “Negative pricing can occur when serving the next increment of demand would actually save the system money; that is, the marginal cost to serve load is negative,” such as “minimum generation periods during which resources (e.g., coal, nuclear, hydro) cannot be shut down,” and “during periods of high variable renewable energy generation and low loads.”³⁰ The concern with negative pricing, as summarized by the National Renewable Energy Laboratory, is as follows:

26. 142 F.E.R.C. ¶ 61,108 (LaFleur, C., concurring).

27. *ISO New England, Inc. and New England Power Pool Participants Committee*, 147 F.E.R.C. ¶ 61,173 (2014).

28. EXELON, 2013 EXELON SUSTAINABILITY REPORT 4 (2013).

29. Complaint Requesting Fast Track Processing, *Independent Power Producers of New York v. New York Independent System Operator, Inc.*, Docket No. EL13-62-000 (May 13, 2013).

30. JAQUELIN COCHRAN ET AL., MARKET EVOLUTION: WHOLESALE ELECTRICITY MARKET DESIGNS FOR 21ST CENTURY POWER SYSTEMS 17, 21ST CENTURY POWER PARTNERSHIP (2013).

One concern about negative pricing in the United States is that with the production tax credit—which in 2013 offers wind generators a \$0.023 subsidy for each kilowatt-hour of energy produced—wind energy can still generate revenue when prices have become negative. They then can offer negative prices representing this “effective” cost of generating. This subsidized bidding can distort the clearing price and impact the rest of the generation fleet. A second concern with negative pricing is that it makes revenue streams more difficult to calculate, and therefore can deter investors from participating in energy markets.³¹

Similarly, as argued by the NorthBridge Group in its report on negative pricing:

Negative prices in themselves are not inherently bad. If they reflect real time underlying physical and economic constraints (i.e., low demand and operational inflexibility) they send the right market signals. But, if they are subsidy-driven and unrelated to real time operational and economic constraints, they distort the market by sending incorrect price signals which harm the reliable and cost effective operation of the electric system. Unfortunately, wind producers’ negative bids fall into this latter category.³²

As more wind generation is added to the grid and load growth remains flat or negative in many areas of the country, the frequency and level of negative prices can become quite significant. For example, California lowered its bid floor to negative \$130 Megawatt hours (MWH) to reflect the increasing level of negative prices produced by the production tax credit (PTC) and state renewable mandates.³³

Not surprisingly, wind interests take sharp exception to criticism of negative prices. American Wind Energy Association (AWEA) has argued, among other things, that negative prices are rare events, the production cost tax credit benefits consumers, and the financial woes of nuclear plants are related primarily to low natural gas prices, not renewable resource subsidies. According to AWEA: “The real impact of wind energy on electricity markets is that it displaces more expensive, polluting sources of energy with zero-fuel-cost wind energy, driving down electricity prices and saving consumers money. This impact is an entirely market-based phenomenon that occurs whether or not wind energy receives the PTC.”³⁴

D. Distributed Generation

Another subsidy that has been controversial in some states is “net metering” for distributed (behind-the-meter) generation, particularly rooftop solar installations. Net metering allows retail customers to offset their electricity purchases from the grid with energy generated behind the retail meter.³⁵ Because

31. *Id.* at 18.

32. FRANK HUNTOWSKI ET AL., NORTHBRIDGE GRP., NEGATIVE ELECTRICITY PRICES AND THE PRODUCTION TAX CREDIT: WHY WIND PRODUCERS CAN PAY US TO TAKE THEIR POWER—AND WHY THAT IS A BAD THING (2012).

33. *California Independent System Operator Corp.*, 145 F.E.R.C. ¶61,254 at PP 22, 46 (2013) (approving lowering of bid floor to negative \$130 MWH and noting concerns regarding effects on conventional generators but declining to initiate technical conference).

34. AM. WIND ENERGY ASS’N, THE FACTS ABOUT WIND ENERGY’S IMPACT ON ELECTRIC MARKETS: CUTTING THROUGH EXELON’S CLAIMS ABOUT “NEGATIVE PRICES” AND “MARKET DISTORTIONS” 3-4 (2014).

35. For an overview of net metering programs in the various states, see generally ASHLEY BROWN & FRANCESCA CILIBERTI-AYRES, DEVELOPMENT OF DISTRIBUTED GENERATION IN THE UNITED STATES (2012).

this offset typically applies to the entire bundled rate—including generation, transmission, and distribution charges—net metering provides two related forms of subsidy, as explained by David Raskin.³⁶ First, because the bundled rate includes transmission and distribution charges, net metering allows customers to avoid paying grid charges despite continuing to rely on the grid for reliable service. Second, because bundled retail rates are, on average, higher than the market price for energy, net metering allows similarly situated renewable energy resources to earn different rates depending on their location with respect to the customer meter.³⁷

The cost of net metering subsidies is causing the greatest concern in states with high rooftop solar penetration. In California, there is an aggressive “Million Solar Roofs” program providing various incentives for rooftop solar.³⁸ After legislation required the California Public Utilities Commission (CPUC) to evaluate the cost of the program, the CPUC’s Energy Division estimated the overall subsidy could reach \$1.1 billion by 2020 and noted the cost of the subsidy would fall disproportionately on lower income households.³⁹

A similar issue arose in Arizona and the state commission adopted, by a narrow 3-2 vote, changes to its net metering program.⁴⁰ The affected utility, Arizona Public Service (APS), had argued rooftop solar installations were increasing at a rapid rate and had already produced a cost shift of \$1,000 per residential household per year.⁴¹ APS, therefore, sought changes to the program to address the cost shifts, but also sought to grandfather existing net metering customers because of their reliance interests in procuring solar installations based on the subsidies. The state commission did not approve the utility’s proposal, but rather, a limited proposal by its staff to require new net metering customers (but not grandfathered customers) to pay some of the transmission and distribution costs that could be avoided under existing rules.⁴²

The states are not alone in being criticized for subsidizing distributed generation. The FERC’s major initiative to reduce barriers to demand response in organized markets, Order No. 745, was sharply criticized by a broad cross-section of the industry as subsidizing demand response by “paying it twice” (once, through a FERC-ordered, full locational marginal price (LMP), and the second time, through avoided state retail generation charges). Commissioner Moeller, in dissent, argued “[n]othing distinguishes a generator that is behind-the-meter from one that is in front-of-the-meter such that it is just and reasonable to pay one

36. Raskin, *supra* note 4, at 38, 40-41.

37. *Id.* at 41; *see also* EDISON ELECTRIC INST., DISRUPTIVE CHALLENGES: FINANCIAL IMPLICATIONS AND STRATEGIC RESPONSES TO A CHANGING RETAIL ELECTRIC BUSINESS (2013).

38. *See generally* A Million Solar Roofs, ENVIRONMENT CALIFORNIA, <http://www.environmentcalifornia.org/programs/million-solar-roofs> (last visited Sept. 13, 2014).

39. CAL. PUB. UTILS. COMM’N, CALIFORNIA NET ENERGY METERING RATEPAYER IMPACTS EVALUATION, (2013), *available at* <http://www.cpuc.ca.gov/NR/rdoonlyres/D74C5457-B6D9-40F4-8584-60D4AB756211/0/NEMReportwithAppendices.pdf>.

40. *In re* Arizona Public Service Company’s Application for Approval of Net Metering Cost Shift Solution, Decision No. 74202, Docket No. E-1345A-13-0248 (Ariz. Corp. Comm’n Dec. 3, 2013).

41. *Id.* at 3.

42. *Id.* at 23.

generator double the rate that is paid to another.”⁴³ The D.C. Circuit agreed with Commissioner Moeller, holding that, even if the FERC had jurisdiction which the court found lacking, “the potential windfall to demand response resources seems troubling.”⁴⁴ This decision is discussed in more detail in Section III.A.

E. Subsidies and PURPA

To stimulate an independent generation sector and to help the Nation diversify its generation supply, Congress enacted PURPA in 1978. One of PURPA’s core provisions was the “mandatory purchase obligation” imposed on electric utilities.⁴⁵ This purchase obligation was cabined, however, by the rule utilities need not pay “qualifying facilities” (cogeneration or small power production) more than their “avoided cost,” i.e., the cost they would have incurred “but for” the qualifying facility (QF) purchase.⁴⁶ The intent was to “make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives”⁴⁷ and thus ensure “consumers are not forced to subsidize QFs.”⁴⁸

This admirable principle did not, however, work out so neatly in the real world. “Several states embraced PURPA with gusto, requiring utilities in these states to sign long-term contracts (twenty to thirty years) with QFs at what later turned out to be extremely high prices compared with the costs of power in competitive wholesale markets.”⁴⁹ These over-market contracts, when combined with billions in over-market nuclear costs, excess supply, and low wholesale market prices, caused a revolt among large customers and state politicians in the 1990s against traditional regulation in favor of competitive markets.⁵⁰ The push for retail access became so politically powerful that in a few short years, approximately half the states had abandoned traditional regulation of the generation sector in favor of retail competition.⁵¹

This shift in focus to competitive markets put the brakes on aggressive implementation of PURPA at the state level, and in the few places where it did not, the FERC intervened. In the most prominent case from that era, the California utilities complained in 1995 the CPUC was attempting to require them, on the eve of deregulation in California, “to purchase significant amounts of unneeded QF

43. *Demand Response Compensation in Organized Wholesale Energy Markets*, 137 F.E.R.C. ¶ 61,215 (2011) (Moeller, C., dissenting).

44. *Elec. Power Supply Ass’n v. FERC*, No. 11-1486, slip op. at 15 (D.C. Cir. May 23, 2014).

45. See generally *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

46. 18 C.F.R. § 292.304.

47. *Southern California Edison Co.*, 71 F.E.R.C. ¶ 61,269 at 62,079-80 (1995).

48. *Indep. Energy Producers Ass’n v. Cal. Pub. Utils. Comm’n*, 36 F.3d 848, 858 (9th Cir. 1994); see also *American Paper*, *supra* note 45, at 415 n.9 (“[E]ven when utilities purchase electric energy from qualifying facilities at full avoided cost rather than at some lower rate, the rates the utilities charge their customers will not be increased, for by hypothesis the utilities would have incurred the same costs had they generated the energy themselves or purchased it from other sources.”).

49. PAUL L. JOSKOW, *DEREGULATION AND REGULATORY REFORM IN THE U.S. ELECTRIC POWER SECTOR, DEREGULATION OF NETWORK INDUSTRIES, WHAT’S NEXT?* 126 (Sam Pelzman & Clifford Winston eds., 2000).

50. *Id.*

51. John S. Moot, *Economic Theories of Regulation and Electricity Restructuring*, 25 *Energy L.J.* 273, 274 (2004).

capacity at prices far in excess of their avoided costs.”⁵² Eschewing the “wide latitude” it had long given states to set avoided cost rates, the FERC rejected the California program because it did not consider “all sources” of energy and explained that the emergence of competitive markets required it to be more vigilant in protecting against QF subsidies.⁵³ Commissioner Massey put the point quite succinctly in his concurring opinion: “[t]he QF industry has matured sufficiently that QFs can and should compete on the merits with other supply options.”⁵⁴

Congress later adopted essentially the same view—i.e., many QFs were now ready to compete on a level playing field in competitive markets—when it enacted EAct 2005. EAct 2005 gave the FERC authority, through new section 210(m) of PURPA, to terminate a utility’s mandatory purchase obligation if QFs in its territory had nondiscriminatory access to competitive markets.⁵⁵ The FERC implemented section 210(m) of EAct by establishing various rebuttable presumptions, including the presumption that Day 2 markets satisfied the statutory standard for large QFs but not for small QFs (under twenty megawatts, or MWs).⁵⁶

PURPA did not go silently into the night, however. Falling market prices have again made the potential for higher avoided cost rates attractive and, in some states, PURPA is again being used to address broader energy policy priorities. This dynamic, in turn, has again placed the FERC at the middle of recurring disputes on both sides of the issue.

One of the more notable disputes involved California’s “feed-in tariffs,” which require certain utility purchases of distributed generation, including renewable energy.⁵⁷ The California utilities challenged the state-mandated rates as preempted by the FERC’s exclusive jurisdiction over wholesale sales. The FERC agreed and rejected California’s argument that states have jurisdiction over wholesale sales by “distributed generation.”⁵⁸ Consequently, the FERC held California could prescribe rates only for distributed generators meeting the standards for small QFs under PURPA (i.e., under twenty MWs).⁵⁹ This finding, in turn, put PURPA “avoided cost” issue front and center. California sought clarification it could adopt a “multi-tiered” avoided cost structure in which the

52. *Southern California Edison Co.*, 70 F.E.R.C. ¶ 61,215 (1995).

53. *Id.* at ¶ 61,675.

54. *Id.* at ¶ 61,678 (Massey, C., concurring).

55. 16 U.S.C. § 824a-3.

56. Order No. 688, *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, F.E.R.C. STATS. & REGS. ¶ 31,233, 71 Fed. Reg. 64,342 (2006) (codified in 18 C.F.R. § 292.309); *see also id.* at P 6:

The FERC found that its rule would ‘continue to support QF development by ensuring that, where the requirements of Section 210(m) are met, QF development will, as determined by Congress, be stimulated by market forces, and that where those requirements have not been met, QF development will continue to be stimulated as it is today through the mandatory purchase obligation.

57. *See generally* Frank R. Lindh & Thomas W. Bone Jr., *State Jurisdiction Over Distributed Generators*, 34 ENERGY L.J. 499, 501 (2013).

58. *California Public Utilities Commission*, 132 F.E.R.C. ¶ 61,047 at PP 5-6, 16-18 (2010) [hereinafter *CPUC Declaratory Order*], *order granting clarification*, 133 F.E.R.C. ¶ 61,059 (2010) [hereinafter *CPUC Clarification Order*], *order denying reh’g*, 134 F.E.R.C. ¶ 61,044 (2011) [hereinafter *CPUC Order Denying Rehearing*].

59. *CPUC Declaratory Order*, *supra* note 58, at PP 67-69.

rates for distributed generators are set based on the costs of long-term contracts for renewable energy sources, not “all sources” (e.g., short-term purchases from gas-fired generation).⁶⁰ The utilities opposed the request, arguing the FERC had rejected that approach in its seminal 1995 order (discussed above).⁶¹ The FERC agreed with California, however, and overruled its 1995 decision to make clear states can base avoided cost rates on a subset of environmentally preferred resources.⁶²

The FERC has also been drawn into an increasing number of disputes generated from the other direction—namely, renewable resources alleging states are violating PURPA and thereby unlawfully preventing their entry. In several of these cases, the FERC has sided with wind developers and found states rules were inconsistent with PURPA. For example, the FERC disagreed with Texas locational marginal prices in a congested region of Southwest Power Pool, Inc.’s (SPP’s) Day 1 market satisfied the avoided cost standard.⁶³ In several other cases, the FERC has rejected Idaho PUC rules, including rules governing wind curtailments during light load periods⁶⁴ and the orders concerning the timing of when wind developers could take advantage of long-term avoided cost rates.⁶⁵ One such case prompted a dissent by Commissioner Clark which, although cautioning the FERC against unnecessary intervention in state proceedings, underscored the recurring question of whether PURPA is being used to level the competition or tilt it in favor of QFs:

[W]hile PURPA was designed as a foot in the door for emerging renewable resources and small generators, I sympathize with concerns that PURPA is increasingly being used as a cudgel that could force consumers to bear undue burdens. For all of the positive attributes of renewable resources, PURPA construct itself creates a challenge for states charged with balancing the integration of variable resources with the needs of end use consumers.⁶⁶

60. *CPUC Clarification Order*, *supra* note 58, at P 26 (“... explicitly implement AB 1613 pursuant to the provisions of [the] PURPA, and, in particular, a proposal to explicitly set new avoided cost rates using a multi-tiered avoided cost rate structure.”).

61. 70 F.E.R.C. ¶ 61,215.

62. *CPUC Clarification Order*, *supra* note 58, at P 30. Using a simplified example, the FERC explained that “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 specified 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.” *Id.* at P 27; *see also CPUC Order Denying Rehearing*, *supra* note 58, at PP 30-33.

63. *Exelon Wind 1, LLC*, 140 F.E.R.C. ¶ 61,152 at P 52 (2012):

The problem with the methodology proposed by SPS and adopted by the Texas Commission is that it is based on the price that a QF would have been paid had it sold its energy directly in the EIS Market, instead of using a methodology of calculating what the costs to the utility would have been for self-supplied, or purchased, energy ‘but for’ the presence of the QF or QFs in the markets, as required by the Commission’s regulations.

64. *Idaho Wind Partners 1, LLC*, 140 F.E.R.C. ¶ 61,219 (2012).

65. *Murphy Flat Power, LLC*, 141 F.E.R.C. ¶ 61,145 (2012); *Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 (2011).

66. *Murphy Flat Power*, 141 F.E.R.C. ¶ 61,145 (Clark, C., dissenting).

III. LEGAL AUTHORITY: WHAT CAN THE FERC DO?

A. *Climate Change*

The politically charged question lurking beneath the legal niceties of the debate over subsidies is whether the FERC can or should take more aggressive action to address climate change. Many in the environmental community argue it both can and should. For example, the Berkeley Energy and Climate Institute recently released a report advocating the FERC take aggressive action on this front, such as creating a price for carbon in wholesale electricity market design.⁶⁷ The premise of this recommendation is “fossil fuel generators are not required to pay the environmental costs of their carbon dioxide emissions,” and therefore, “they enjoy a competitive advantage over renewable energy producers.”⁶⁸ The report recommends the FERC “remove this advantage by including a carbon adder, reflecting the cost of climate and other environmental damage caused by carbon dioxide, in wholesale electricity rates.”⁶⁹ The report argues the Supreme Court’s decision in *National Association for Advancement of Colored People v. Federal Power Commission*⁷⁰ establishes the premise that the FERC can consider environmental issues when setting wholesale rates.⁷¹

This recommendation rests on a misreading of *NAACP v. FPC*. Although the Court stated in a footnote “the Commission has authority to consider conservation [and] environmental . . . questions,” it was referring to the FPC’s authority over hydroelectric facilities under Part I of the FPA.⁷² Unlike the FERC’s jurisdiction over wholesale sales under Part II of the FPA, however, Part I gives the FERC jurisdiction to consider environmental impacts in regulating a hydroelectric project.⁷³ The FERC does not, however, possess the same authority over coal plants or other fossil fuel generators and, indeed, FPA Part II put direct regulation of generating facilities beyond the FERC’s reach.⁷⁴

This does not mean the FERC has no authority over carbon emissions as it relates to wholesale market design. As illustrated by California’s cap-and-trade program, once another governmental entity imposes a limit on greenhouse gases, the FERC has clear authority to modify wholesale tariffs as necessary to incorporate those limits. This ordinarily involves modifying the price at which generators are compensated when mitigated for market power or other reasons. As the FERC explained when approving the change in California market design:

67. STEVEN WEISMANN & ROMANY WEBB, ADDRESSING CLIMATE CHANGE WITHOUT LEGISLATION: HOW THE FEDERAL ENERGY REGULATORY COMMISSION CAN USE ITS EXISTING LEGAL AUTHORITY TO REDUCE GREENHOUSE GAS EMISSIONS AND INCREASE CLEAN ENERGY USE, BERKELEY ENERGY & CLIMATE INITIATIVE (2013), available at http://www.law.berkeley.edu/files/ccelp/FERC_Report_FINAL.pdf.

68. *Id.* at 2.

69. *Id.*

70. *NAACP v. FERC*, 425 U.S. 662 (1972).

71. *Id.*

72. *Id.* at 670 n.6 (citing, in pertinent part, 16 U.S.C. § 803(a) and *Udall v. FPC*, 387 U.S. 428 (1967), both of which concern Part I of the FPA).

73. 16 U.S.C. § 824(b) (The FERC “shall not have jurisdiction [under Part II] over facilities used for the generation of electric energy”); *Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (2009) (contrasting the FERC’s authority over wholesale rates with state authority over generation siting and certification).

74. 16 U.S.C. § 824(c).

As a general matter, we find that it is reasonable to incorporate the emissions costs of the greenhouse gas allowances into the calculation of generating units' variable costs as calculated in CAISO's tariff. Such a revision is required in order to provide generators a reasonable opportunity to recover their variable energy costs incurred as a result of the California Program.⁷⁵

Admittedly, however, there are limits to the effectiveness of such wholesale market design changes in a world where some states have acted to address climate change but others have not. This issue—commonly described as “leakage,” where emissions reductions achieved by those states or countries which act first are undermined by emission increases in states or countries that do not act⁷⁶—is one the FERC cannot solve on its own. However, if the EPA finalizes its proposed rulemaking on regulating greenhouse gas emissions, every state will be bound to take some action to reduce greenhouse gas emissions (although individual state requirements will vary widely).⁷⁷ If such a final rule is adopted, the FERC may be asked to exercise its jurisdiction over regional wholesale market design to facilitate state compliance with EPA's rulemaking. For example, the ISO/RTO Council has already begun working on regional measurement and compliance options that could be incorporated into wholesale market design.⁷⁸

The FERC also has affirmative authority to address challenges faced by renewable resources using its power to remedy undue discrimination. Section 205 of the FPA provides that “[a]ll rates and charges . . . in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable,” and no “undue preference or advantage” shall be given “to any person” in setting those rates.⁷⁹ Although this statutory framework precludes the FERC from favoring particularly energy resources or technologies, it gives the FERC the power and responsibility to remove barriers to their development which are “unduly discriminatory.” A preference can be “undue” where similarly situated resources (or customers) are treated differently or where different classes of resources (or customers) are unreasonably treated the same.⁸⁰

The Commission has exercised this authority under both Democratic and Republican Administrations to remove unreasonable barriers to the development of clean energy sources. One of the first examples was the FERC approval of a special interconnection rule in California for “location-constrained resources,” a class defined primarily, but not exclusively, to include wind and solar generators.⁸¹

75. *California Independent System Operator Corp.*, 141 F.E.R.C. ¶ 61,237 at P 29 (2012).

76. CAROLYN FISCHER & ALAN K. FOX, *COMPARING POLICIES TO COMBAT EMISSIONS LEAKAGE: BORDER CARBON ADJUSTMENTS VERSUS REBATES* (2011); LARRY PARKER & JOHN BLODGETT, “CARBON LEAKAGE” AND TRADE: ISSUES AND APPROACHES, CONG. RESEARCH SERV. (2008).

77. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 117 (proposed June 18, 2014) (to be codified at 40 C.F.R. pt. 60).

78. ISO/RTO COUNCIL, EPA CO₂ RULE—ISO/RTO COUNCIL RELIABILITY SAFETY VALVE AND REGIONAL COMPLIANCE MEASUREMENT PROPOSALS (2014), *available at* http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf.

79. 16 U.S.C. §§ 824d(a)-(b) (2012). The Natural Gas Act contains similar statutory commands. 15 U.S.C. § 717c.

80. *See, e.g., Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 238 (D.C. Cir. 2013).

81. *California Independent System Operator Corporation*, 119 F.E.R.C. ¶ 61,061 (2007).

The FERC found the proposal appropriate to remedy undue discrimination because “[o]ur [general] interconnection policy assumes that generators . . . can choose where to interconnect and will do so in an economically efficient manner,” but location-constrained resources “present unique challenges that are not faced by other resources and that are not adequately addressed in the Commission’s current interconnection policies.”⁸² The same year, the Commission adopted a generic reform of “energy imbalance” charges that rested on a similar premise. The FERC created an exemption for “intermittent generation” (again, a class defined primarily, but not exclusively, by wind and solar generation) because intermittent generators do not have the same ability as traditional generators to control their output to minimize imbalances between scheduled and actual output.⁸³

More recently the Commission has modified its transmission planning and cost allocation rules to accommodate the integration of renewables. For example, in Order No. 1000 the Commission required transmission owners to consider “public policy” requirements (a class defined primarily, but not exclusively, by renewable energy mandates) in their planning processes.⁸⁴ Many criticized this category as implicitly encouraging a subsidy for wind resources, but the Commission disagreed, finding “[b]ecause we are not mandating the consideration of any particular transmission need driven by a Public Policy Requirement, we disagree with [commenters] that we are favoring renewable energy resources over other types of resources.”⁸⁵ The Commission has also approved certain proposals that spread to all customers the cost of transmission upgrades constructed to integrate wind generation, rather than allocating those costs directly to wind generators.⁸⁶

A line can be crossed, however, when removing barriers to clean energy technologies. A prominent example occurred when the FERC sought to reduce barriers to demand response in organized markets. The FERC’s pricing reforms were criticized as subsidizing—not reducing discriminatory barriers to—demand response by allowing it to be “paid twice” (once through a FERC-ordered full locational marginal price (LMP) and the second time by avoiding state-approved retail generation charges).⁸⁷ The FERC disagreed, finding “removing barriers to

82. *Id.* at PP 64-65.

83. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, F.E.R.C. STATS. & REGS. ¶ 31,241 at P 667 (a “partial exemption from imbalance charges for intermittent resources appropriately reflects the special circumstances faced by such resources and, consequently, is not unduly discriminatory”), *order on reh’g and clarification*, Order No. 890-A, F.E.R.C. STATS. & REGS. ¶ 31,261 (2007), *order on reh’g and clarification*, Order No. 890-B, F.E.R.C. STATS. & REGS. ¶ 31,241 (2008), *order on reh’g*, Order No. 890-C, 126 F.E.R.C. ¶ 61,228, *order on clarification*, Order No. 890-D, 129 F.E.R.C. ¶ 61,126 (2009) (codified at 18 C.F.R. pts. 35 and 37).

84. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,323 at P 215 (2011) (codified at 18 C.F.R. pt. 35.28), *pet. for rev. denied*, S. Carolina Pub. Serv. Authority v. FERC, No. 12-1232, 2014 WL 3973116 (D.C. Cir. Aug. 15, 2014).

85. *Id.*

86. *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 133 F.E.R.C. ¶ 61,221 (2010) (*MVP Order*), *reh’g denied*, 137 F.E.R.C. ¶ 61,074 (2011), *pet. for review denied*, Ill. Commerce Comm’n v. FERC, 721 F.3d 758 (7th Cir. 2013).

87. Order No. 745, *Demand Response Compensation in Organized Markets*, Order No. 745, F.E.R.C. STATS. & REGS. ¶ 61 at P 59 (to be codified at 18 C.F.R. pt. 35).

demand response participation is not the same as giving preferential treatment to demand response providers; rather, it facilitates greater competition, with the markets themselves determining the appropriate mix of resources, which may include both generation and demand response, needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets.”⁸⁸ But the D.C. Circuit struck down the FERC’s order on jurisdictional grounds and because the FERC’s pricing rule gave demand response a “potential windfall.”⁸⁹

In sum, the FERC has significant authority to address some of the issues commonly associated with the climate change debate, but that authority has limits. First, the FERC can remove barriers to participation by renewable resources in wholesale power markets or in securing transmission or interconnection service if those barriers constitute an undue preference. That preference must relate to a matter within the FERC’s jurisdiction, however, not a matter committed to the jurisdiction of other governmental bodies. Just as the FERC cannot remedy perceived inequities in the tax code by withholding wholesale market revenues from firms allegedly taking advantage of tax loopholes, it cannot counteract Congress’ failure to enact cap-and-trade or carbon tax legislation by creating its own program through a wholesale market design change. Second, when the FERC acts within its jurisdiction to remedy an undue preference, it cannot replace that preference with another undue preference. It must level the playing field, not tilt it anew.

B. *Energy and Capacity Market Subsidies*

The heart of the debate over minimum offer price rules is primarily a normative one—namely, whether the FERC should adopt such rules (and, if so, in what form), not whether the FERC has the legal authority to do so. The Third Circuit’s recent decision in *New Jersey Board of Public Utilities v. FERC*⁹⁰ criticized the FERC’s procedural approach to capacity market mitigation on the particular facts of the case, but had no hesitation in upholding the FERC’s jurisdiction to mitigate subsidized bids as a general matter.⁹¹ The states had argued doing so amounted to direct regulation of generation facilities, thereby violating the limitation on the FERC’s authority contained in FPA section 201, but the court declined to accept the argument:

New Jersey Petitioners argue that, unlike in *Connecticut DPUC*, “FERC here interferes directly and materially with state efforts to sponsor new capacity resources precisely because those efforts could affect market prices.” New Jersey Petitioners are wrong; what FERC has actually done here is permit states to develop whatever capacity resources they wish, and to use those resources to any extent that they wish, while approving rules that prevent the state’s choices from adversely affecting wholesale capacity rates. Such action falls squarely within FERC’s jurisdiction.⁹²

88. *Demand Response Compensation in Organized Markets*, Order No. 745, F.E.R.C. STATS. & REGS. ¶ 61, 187 at P 59, 134 F.E.R.C. ¶ 61,187 (2011), *reversed and vacated*, Elec. Power Supply Ass’n v. FERC, 753 F.3d 216, 225 (D.C. Cir. 2014).

89. *Id.*

90. *N.J. Bd. Of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

91. *Id.*

92. *Id.* at 98-99.

The Court relied, in part, on earlier decisions in *Connecticut Department of Utility Control v. FERC*⁹³ and other cases holding that the FERC's regulation of capacity markets did not constitute a direct regulation of generating facilities contrary to FPA section 201.

In a related vein, two federal appellate courts have struck down state efforts to intervene in organized markets through subsidized wholesale payments. The rationale, as stated by the district court in *Nazarian*, was as follows:

[A]fter a generator physically comes into existence and operation and participates in the wholesale electric energy market, the prices or rates received by that generator in exchange for wholesale energy and capacity sales are within the sole purview of the federal government. While Maryland may retain traditional state authority to regulate the development, location, and type of power plants within its borders, the scope of Maryland's power is necessarily limited by FERC's exclusive authority to set wholesale energy and capacity prices under, *inter alia*, the Supremacy Clause and the field preemption doctrine.⁹⁴

The Fourth Circuit Court of Appeals upheld this ruling, finding, "[a]lthough states plainly retain substantial latitude in directly regulating generation facilities, they may not exercise this authority in a way that impinges on the FERC's exclusive power to specify wholesale rates."⁹⁵ The Third Circuit has upheld a similar challenge to state-sponsored subsidy payments.⁹⁶

These FERC and federal court rulings address a fairly discrete class of state subsidy payments adversely affecting capacity markets, but the FERC's rulings also rest on a broader historical and policy foundation. Many of the FERC's mitigation rules rest on the broader premise that competitive electricity markets are regulated, not left entirely unregulated, to ensure just and reasonable rates. When the FERC's modern day market-based rate program was attacked as "outsource[ing] its regulatory duties to the 'Invisible Hand' of the market," the Ninth Circuit Court of Appeals rejected the challenge, finding the FERC's use of *ex ante* review of structural market power problems and *ex post* review of manipulation met its statutory obligation.⁹⁷ Pertinent here, the FERC has found its *ex ante* review must evaluate both the potential for sellers to raise price above competitive levels as well as the ability of purchasers to lower price below competitive levels. This is because, in the words of the Third Circuit, "[w]hen [load serving entities] buy more capacity than they offer into [a capacity] auction, they have an incentive to keep auction prices as low as possible" and "those net-buyers can achieve that objective by offering their capacity at artificially low prices that are sure to clear the auction."⁹⁸

Although *ex ante* review of buyer-side mitigation in capacity markets is the most prominent issue today, one of the first mitigated bid floors was adopted in

93. Conn. Dep't of Util. Control v. FERC, 569 F.3d 477 (2009).

94. PPL EnergyPlus, LLC v. Nazarian, No. MJG-12-1286, slip op. at 85 (D. Md. 2013).

95. PPL EnergyPlus, LLC v. Nazarian, *supra* note 23, at 477.

96. PPL EnergyPlus, LLC v. Solomon, *supra* note 23.

97. Mont. Consumer Counsel v. FERC, 659 F.3d 910, 919 (9th Cir. 2012) ("By screening for market power before authorizing market-based rates, and by continually monitoring sellers for evidence of market power, FERC has adopted a permissible approach to fulfilling its statutory mandate to ensure that rates are just and reasonable.")

98. N.J. Bd. of Pub. Util. v. FERC, 744 F.3d 74, 85 (2014).

the context of protecting energy markets in California from out-of-market payments. When the FERC first approved the organized markets created in California, it imposed a bid floor to counteract the incentives associated with low bids designed to increase regulated stranded cost recovery.⁹⁹ In other words, it acted to ensure an out-of-market payment did not provide an incentive to skew energy market prices downward, finding “[t]here . . . may be an incentive for the [California utilities] to reduce prices below competitive levels which would accelerate recovery of stranded costs through the [competitive transition charge]”).”¹⁰⁰ In context, a low energy bid could accelerate stranded cost recovery because stranded cost calculations were pegged to prevailing market prices.

The FERC also has policies to protect bilateral wholesale markets from the effects of certain regulated subsidies. For example, the FERC imposes an indirect incremental cost floor on wholesale “coordination” transactions by regulated sellers with captive customers, the theory being that captive customers should not subsidize energy sales in a competitive market.¹⁰¹ Although the focus of this rule is preventing captive customers from bearing a subsidy, it also has the corollary effect of removing incentives to depress market prices through below-cost energy sales. The FERC also imposes rules on affiliate sales that are designed to ensure captive customers of regulated companies do not subsidize sales in competitive markets.¹⁰² The FERC requires transmission providers to apply their own transmission tariff rates when making off-system energy sales, thereby ensuring they do not undercut the competition by avoiding the same transmission rate imposed on competitors.¹⁰³

The FERC has also recognized that even FERC-approved payments can adversely affect economic dispatch decisions. For this reason, the FERC has ruled certain payments (e.g., marginal line loss credits) should not be assessed (or credited) in a manner that skews economic dispatch or trading decisions.¹⁰⁴ Similarly, the FERC has recognized out-of-market payments in FERC-approved reliability must-run agreements should be minimized “because they distort market

99. *Pacific Gas & Elec. Co.*, 81 F.E.R.C. ¶ 61,122 (1997).

100. *Id.* at 61,547.

101. *Electric Cooperative, Inc. v. Southwestern Public Serv. Co.*, Opinion No. 501, 123 F.E.R.C. ¶ 61,047 at P 41 (2005) (“Preventing such subsidization was the original reason for requiring that utilities price opportunity sales at a price that, at a minimum, made wholesale requirements customers economically indifferent to the sales”); *id.* at P 44 (“To impute something different from incremental costs as a surrogate for the actual fuel cost could allow market-based rate sellers to include an artificially low fuel cost into their market-based rate contracts.”); *see also Entergy Services, Inc.*, 58 F.E.R.C. ¶ 61,234 at 61,772 (1992).

102. *Market Based Rates for Wholesale Sales of Energy, Capacity and Ancillary Services by Public Utilities*, 119 F.E.R.C. ¶ 61,295 at P 526 (2007); *see also Southern California Edison Co.*, 106 F.E.R.C. ¶ 61,183 at P 59 (2004) (“We are also concerned that granting undue preference to affiliates, whether through cost-based or market-based transactions, could cause long-term harm to the wholesale competitive market Affiliate preference could discourage non-affiliates from adding supply in the local area, harming wholesale competition and, ultimately, wholesale customers.”); *Heartland Energy Services, Inc.*, 68 F.E.R.C. ¶ 61,223, 61,062 (1994).

103. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 682 (D.C. Cir. 2000).

104. *Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 240 (D.C. Cir. 2013) (noting that the FERC distributes excess transmission line loss revenues based on a load serving entities contribution to the fixed costs of the system because “any formula that disburses surplus to the virtual marketers according to trading volume will create incentives for them to focus on increasing their surplus disbursements by increasing their trading volume”).

clearing prices in a way that understates the value of resources necessary to reliably serve load.”¹⁰⁵

Despite this ample precedent, some may question whether the D.C. Circuit’s recent opinion in *Electric Power Supply Ass’n v. FERC (EPSA)*¹⁰⁶ undermines the FERC’s jurisdiction in this area. I would suggest the answer is no. In that case, the FERC had justified its assertion of jurisdiction over demand response on the rationale that demand response “affects” wholesale markets. The court agreed “demand response compensation affects the wholesale market,” but found that justification lacking because it “has no limiting principle” and thus “could ostensibly authorize the FERC to regulate any number of areas, including the steel, fuel, and labor markets.”¹⁰⁷

The court’s holding, whether one agrees with it or not, stands for the relatively straightforward proposition that the FERC cannot *directly* regulate retail sales (or consumption) simply by asserting that it “affects” wholesale rates. The Supreme Court has long held the FPA established “a bright line easily ascertained, between state and federal jurisdiction.”¹⁰⁸ This bright line means that the FERC’s jurisdiction is “plenary and extend[s] . . . to all wholesale sales in interstate commerce,” but states retain exclusive jurisdiction to regulate retail sales.¹⁰⁹ It is thus “common ground” under this bifurcated scheme “that if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject.”¹¹⁰

The court in *EPSA* sought to apply this bright line test when it held that demand response “is not a wholesale sale of electricity” and “in fact, it is not a sale at all,” which in turn meant, even if it “affects” wholesale rates, that fact alone does not give the FERC jurisdiction over it.¹¹¹ Importantly, this finding is consistent with the Third Circuit’s decision in *New Jersey* that had addressed the converse fact pattern. In that case, the court held the mere fact that the FERC’s wholesale mitigation rules may affect state resource planning prerogatives does not invalidate the FERC’s rules. Rather, unless the FERC has *directly* regulated matters left to the states, it retains “plenary” jurisdiction over wholesale markets, including the authority and responsibility to ensure that wholesale rates are just, reasonable and not unduly discriminatory.¹¹² The court in *Electric Power Supply Ass’n v. FERC* was careful not to deviate from this rule when it made clear that “FERC can regulate practices affecting the wholesale market under [sections] 205 and 206, provided the Commission is not *directly* regulating a matter subject to state control, such as the retail market.”¹¹³

105. *Richard Blumenthal v. ISO New England, Inc.*, 117 F.E.R.C. ¶ 61,038 at P 58 (2006).

106. *Elec. Power Supply Ass’n v. FERC*, 753 F.3d 216, 221 (D.C. Cir. 2014).

107. *Id.* at 221.

108. *Fed. Power Comm’n v. S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964).

109. *Id.* at 216.

110. *Miss. Power & Light Co. v. Mississippi*, 487 U.S. 354, 377 (1988) (Scalia, J., concurring in the judgment).

111. *Elec. Power Supply Ass’n*, 753 F.3d at 220-21.

112. *New Jersey*, *supra* note 22, at 97 (rejecting argument that “FERC is preventing New Jersey from using the resources it has chosen to promote” by simply mitigating the bids from such resources).

113. *Elec. Power Supply Ass’n*, 753 F.3d at 222 (emphasis added).

The FERC itself has stressed the same point, finding that, although it has the authority and obligation to protect competitive markets from harmful subsidies, this does not foreclose states from pursuing their own policy objectives that are not dependent on price suppression:

The Commission acknowledges the rights of states to pursue policy interests within their jurisdiction. Our concern, however, is where pursuit of these policy interests allows uneconomic entry of [out of market] capacity into the capacity market that is subject to our jurisdiction, with the effect of suppressing capacity prices in those markets. We note that our primary concern stems not from the state policies themselves, but from the accompanying price constructs that result in offers into the capacity market from these resources that are not reflective of their actual costs.¹¹⁴

C. Distributed Generation

The FERC has held in two decisions, *MidAmerican Energy Co.*¹¹⁵ and *Sun Edison LLC*,¹¹⁶ that it does not have jurisdiction over sales from distributed generation if those sales are not positive over a monthly billing cycle:

[W]here there is no net sale over the applicable billing period to the local load-serving utility, there is no sale; accordingly, where there is no net sale over the applicable billing period to the local load-serving utility by the end-use customer that is the purchaser of SunEdison's solar-generated electric energy, SunEdison is likewise not making a sale 'at wholesale,' i.e., a 'sale for resale'.¹¹⁷

When this finding was first made in *MidAmerican*, the Commission justified its rationale, in part, by reference to its policy on a fact pattern that presented the opposite situation: when a generator consumes energy from the grid for station power use in some hours, but has a net sale to the grid over a monthly billing period.¹¹⁸ Since that time, however, this latter ruling on station power has been reversed by the D.C. Circuit.¹¹⁹

David Raskin has thoroughly addressed the shortcomings of the FERC's decision to rest the jurisdictional nature of a sale on a monthly billing period.¹²⁰ This article will therefore only supplement his analysis with two additional points.

First, the decision to rest the jurisdictional determination on a billing (payment) period is understandable from a political perspective—namely, the FERC not wanting to interfere with state retail programs—but it is hard to reconcile, either as a matter of principle or practice, with the “bright line” established by Congress in the Federal Power Act. The FERC has disclaimed jurisdiction over net metering programs so long as the state establishes a “reasonable” billing cycle,¹²¹ but Congress chose “a bright line easily ascertained between state and federal jurisdiction” under which the FERC's jurisdiction is

114. 135 F.E.R.C. ¶ 61,029 at P 170.

115. 94 F.E.R.C. ¶ 61,340 (2001).

116. 129 F.E.R.C. ¶ 61,146 (2009).

117. *Id.* at P 19.

118. *MidAmerican*, 94 F.E.R.C. ¶ 61,340 at 62,262.

119. *S. Cal. Edison Co. v. FERC*, 603 F.3d 996 (D.C. Cir. 2010).

120. Raskin, *supra* note 4.

121. *Sun Edison LLC*, 129 F.E.R.C. ¶ 61,146 at P 18 n.10 (“The Commission, in *MidAmerican*, found that a one-month billing period was reasonable, but indicated that other billing periods could also be reasonable”).

“plenary and extend[s] it to all wholesale sales in interstate commerce.”¹²² Importantly, when exercising its jurisdiction over wholesale sales, the FERC has held there is no *de minimis* exception to FERC jurisdiction¹²³ and also that, where two entities exchange power, the FERC treats each side of the transaction as a sale.¹²⁴ Moreover, because electricity cannot generally be stored, it follows that whenever a distributed generator produces net energy to the grid in any hour, that energy must be resold to other customers in that hour. It is difficult to reconcile these legal principles and physical realities with the notion that the FERC’s jurisdiction over net metering should turn on the relative billing cycle set by the state.

There are also practical perils in making the FERC’s jurisdictional test dependent on billing cycles, as can be illustrated with a hypothetical. Assume there is an electric company serving a large metropolitan area (City Electric) entirely surrounded by a single, large regional electric utility (Regional Electric). City Electric has 1,000 MW of generation dedicated to serving its retail customers, but occasionally, when it is economic to do so, sells excess energy to Regional Electric and similarly, when it is economic to do so, buys energy from Regional Electric. Over the course of each month, however, City Electric is always a net purchaser of energy and its interconnection contract with Regional Electric has a monthly billing cycle that requires netting of purchases and sales. Is City Electric making FERC-jurisdiction sales? The answer is no under *MidAmerican* and *Sun Edison*, but yes under the other precedents noted above.

Perhaps the best objection to this hypothetical is that City Electric presents the type of situation contemplated by Congress in 1935—i.e., a traditional utility company selling energy to the grid—but that Congress never contemplated regulating sales by a residential homeowner with rooftop solar.¹²⁵ That, of course, is true in the literal sense, but Congress also never contemplated regulating things like RTOs, wind farms, or other technologies not present in 1935. These new forms of organization and technology can present challenges in applying an eighty-year old statute,¹²⁶ but that is a reason to be careful in *how* to apply FERC’s jurisdiction, not a fact that determines *whether* jurisdiction exists.

For example, even if the FERC were to reverse its decision *Sun Edison*, it would not have to regulate residential customers as traditional public utilities. In other situations where the Federal Power Act covers an activity the FERC deems benign, the FERC has used light handed regulation in the form of blanket waivers of its regulations.¹²⁷ The same approach has been applied to distributed generation

122. *Elec. Power Supply Ass’n*, 753 F.3d at 216.

123. *Prior Notice and Filing Requirements*, 64 F.E.R.C. ¶ 61,139, 61,994 (1993) (“The FPA makes no mention of a ‘*de minimis*’ exception for otherwise jurisdictional transactions. Moreover, the courts have rejected the notion.”).

124. *Id.* at ¶ 61,991.

125. Lindh & Bone, *supra* note 57.

126. *See generally* *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1 (2002) (addressing the division of filing authority under FPA section 205 as between public utilities and RTOs).

127. *See, e.g., Transactions Subject to FPA Section 203*, 113 F.E.R.C. ¶ 61,315 (2005) (granting blanket authorization for certain transactions that fall under the Commission’s FPA section 203 jurisdiction, such as the acquisition of foreign utilities, where, even though the statute gives the FERC clear authority, it was not in the public interest to regulate those transactions on a case-by-case basis).

where, for example, the FERC has waived certain PURPA requirements for generators of less than one MW.¹²⁸

The FERC has also deferred to states in limited situations regarding how to regulate FERC-jurisdictional transactions. Prior to Order No. 888, the FERC asserted jurisdiction over unbundled retail transmission arrangements, but ordinarily deferred to the rate-making used by the states for those arrangements.¹²⁹ The FERC has also done the same for wholesale sales in limited circumstances.¹³⁰ I am not suggesting the FERC should assert jurisdiction over wholesale sales from rooftop solar installations but leave all existing state pricing rules in place. Rather, the point is merely that the question of whether an activity is subject to FERC jurisdiction is quite different than the question of *how* to exercise that jurisdiction.¹³¹

Second, apart from whether the FERC has jurisdiction over energy sales in a net metering context, there is also a separate question of its jurisdiction over the transmission service provided to such distributed generation customers. In Order No. 888,¹³² the FERC exercised its jurisdiction over all unbundled transmission service in interstate commerce, but declined to exercise jurisdiction over the transmission component of bundled retail sales. The Supreme Court in *New York v. FERC* upheld the FERC on both counts and, in doing so, noted that the FERC had kept its powder dry on its jurisdiction over the transmission component of bundled retail sales: “the FERC chose not to assert such jurisdiction, but it did not hold itself powerless to claim jurisdiction. Indeed, the FERC explicitly reserved decision on the jurisdictional issue”¹³³ Given that FPA section 201 grants the FERC authority over all “transmission in interstate commerce” and, unlike its jurisdiction over wholesale sales, that jurisdictional grant is not limited by the word “sales” (whether retail or wholesale, bundled or unbundled), there is a compelling argument that the FERC possesses latent jurisdiction over the bundled component of retail transmission service. Indeed, if the rule were otherwise,

128. *Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility*, 130 F.E.R.C. ¶ 61,214 (2010) (exempting QFs of less than one MW from certain filing requirements).

129. *Consolidate Edison Co. of New York*, 15 F.E.R.C. ¶ 61,174, 61,405 (1981) (“In light of the foregoing and the particular circumstances which surround the instant filing, we intend to exercise our jurisdiction over this service, in this and future filings by Con Ed, by accepting the rate determinations of the NYPSC in the absence of a showing that the NYPSC has abused its discretion or violated a public policy, such as the policy against undue discrimination. In other words, we shall not insist that the rates be developed, in all respects, according to the ratemaking practices of this Commission, but will accept the NYPSC’s rate practices and determinations in the absence of a showing of abuse as described above.”).

130. *See, e.g., Northwestern Wisc. Elec. Co.*, 65 F.E.R.C. ¶ 61,302 (1993).

131. 64 F.E.R.C. ¶ 61,139, 61,995 (explaining that, although there is no *de minimis* exception under section 205, the Commission has discretion to decline to impose its regulations where doing so would have “trivial or no” public benefits).

132. *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils. Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, Order No. 888, F.E.R.C. STATS. & REGS. ¶ 31,036, *clarified*, 76 F.E.R.C. ¶ 61,009 (1996), *order on reh’g*, Order No. 888-A, F.E.R.C. STATS. & REGS. ¶ 31,048, *order on reh’g*, Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997), *order on reh’g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998), *aff’d in substantial part sub nom.* *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom.*

133. *New York v. FERC*, 535 U.S. 1, 3 (2002).

FERC's jurisdiction over even wholesale transmission could be avoided simply by bundling energy and transmission together.

The Commission therefore has discretion—whether it chooses to revisit *Sun Edison* or not—to assert jurisdiction over the transmission component of service to customers with distributed generation. One rationale for doing so would be to ensure distributed generation customers pay a just, reasonable, and nondiscriminatory share of transmission costs. As noted previously, the grid is becoming more, not less, critical to the reliable integration of new technology, particularly variable energy resources, and these grid functions support the reliability of the system in all hours of the year, not just hours when particular meters run positive.

For similar reasons, the FERC has rejected the functional equivalent of net metering for wholesale transmission service. In Order No. 888, as clarified in Order No. 888-A, the Commission declined to allow a customer taking network transmission service to net its behind-the-meter generator for purposes of calculating its load ratio share of transmission costs. The Commission reasoned that this could permit a customer to 'game the system' by evading some or all of its load ratio cost responsibility for network [transmission] services.¹³⁴ The Commission was asked to revisit this rule in Order No. 890, but again declined, finding "[t]he Commission is not persuaded to require transmission providers to allow netting of behind the meter generation against transmission service charges"¹³⁵ A similar rationale could support the assertion of jurisdiction over retail net metering for the limited purpose of ensuring all customers pay a nondiscriminatory share of the costs of transmission service in interstate commerce.

D. PURPA Implementation and Competitive Markets

PURPA was an unqualified success in creating an independent power industry that benefits consumers by encouraging innovation and shifting risks away from ratepayers and onto the investors in the generation business. The continued implementation of PURPA is not, however, necessarily costless to society. The nature of the QF "put," which gives QFs the choice to switch back and forth between selling into the market or putting energy to the utility at avoided cost, can require the system operator to procure additional operating reserves (and, hence, costs) to manage the uncertainty.¹³⁶ The differing curtailment rules applicable to QFs can also create operational issues during low load situations.¹³⁷

134. Order No. 888-A, *supra* note 132, at 30,259.

135. *Preventing Undue Discrimination and Preference in Transmission Serv.*, Order No. 890, F.E.R.C. STATS. & REGS. ¶ 31,241 at P 1619, *order on reh'g and clarification*, Order No. 890-A, F.E.R.C. STATS. & REGS. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, F.E.R.C. STATS. & REGS. ¶ 31,241 (2008), *order on reh'g*, Order No. 890-C, 126 F.E.R.C. ¶ 61,228, *order on clarification*, Order No. 890-D, 129 F.E.R.C. ¶ 61,126 (2009) (codified at 18 C.F.R. pts. 35 and 37).

136. CHARLES RIVER ASSOCIATES, COST-BENEFIT ANALYSIS OF ENTERGY AND CLECO POWER JOINING THE SPP RTO at 15 (2010); *see also* CHARLES RIVER ASSOCIATES, ADDENDUM STUDY: COST-BENEFIT ANALYSIS OF ENTERGY AND CLECO POWER JOINING THE SPP RTO (2010).

137. JOINT CAISO-NERC SPECIAL RELIABILITY ASSESSMENT, *supra* note 10, at 10 ("CAISO plans on exploring ways to incentivize Qualifying Capacity (QFs) to curtail production during low net load demand periods in order to minimize the magnitude of potential overgeneration.").

And, although avoided cost rates are theoretically intended to protect consumers from subsidies, history has shown that “administrative” determinations, particularly for long term contracts, can over-estimate future market prices and under-estimate technological improvements.¹³⁸

It is therefore important the FERC exercise its continuing jurisdiction under PURPA with care to avoid subsidies that shift costs to customers or otherwise undermine competitive markets. There are at least two recurring legal issues that will present challenges to the Commission in regulating in this area going forward: (i) whether (and when) to terminate the mandatory purchase obligation for small QFs in organized markets, and (ii) how to apply the avoided cost standard in the context of organized markets. Each is addressed in turn.

1. Terminating the Purchase Obligation re Small QFs.

The FERC has applied section 210(m) of PURPA by terminating the mandatory purchase obligation from large QFs in organized markets, but mostly denied that same relief with respect to small QFs.¹³⁹ With respect to small QFs, the FERC has held that a utility must prove that an organized market not only removes unreasonable entry barriers to entry, but also that *each and every* small QF in fact has taken advantage of the market or is capable of doing so.¹⁴⁰

There is some question whether this approach should be retained going forward. Focusing on *structural* barriers to entry, not anecdotal evidence related to *actual* entry,¹⁴¹ would be more consistent with the animating purpose of PURPA—which was deemed necessary to remove the *structural* barrier to entry posed by utility refusals to purchase from independents. A structural approach also would be more consistent with the animating objective of the antitrust laws, which is to protect competition, not individual competitors.¹⁴² And it would be consistent with the structural approach taken by the FERC when implementing section 210(m) with regard to whether “nondiscriminatory access” to the grid exists. With respect to this criterion, the FERC has held that removal of the mandatory purchase obligation does not turn on individualized findings as to whether a particular utility has complied with its OATT, but rather on the FERC’s structural remedy that requires all transmission providers to provide open access under an OATT.¹⁴³ Moreover, as noted by Commissioners Clark and Moeller in

138. JOSKOW, *supra* note 49.

139. The exceptions are two cases where the utility sought waiver of the purchase obligation from an individual small QF (rather than all small QFs in its territory). *Fitchburg Gas & Electric Light Co.*, 146 F.E.R.C. ¶ 61,186 (2014); *City of Burlington, Vermont*, 145 F.E.R.C. ¶ 61,121 (2013).

140. *Public Service Co. of New Hampshire*, 131 F.E.R.C. ¶ 61,027 (2010); *PPL Electric Utility Corp.*, 145 F.E.R.C. ¶ 61,053 (2013), *reh’g denied*, 148 F.E.R.C. ¶ 61,207 (2014).

141. 145 F.E.R.C. ¶ 61,053 at P 8 (finding that, although the Commission will not “prejudge” the necessary evidentiary, “such evidence could include whether the QF has, in fact, been participating in the market or is owned by, or is an affiliate of, an entity that has been participating in the market,” whereas in the case at bar “the Souderton QF is a new QF not yet in operation, and as such has not been participating in PJM’s markets, and there is no evidence that the Souderton QF will be owned by, or is an affiliate of, an entity participating in PJM’s markets.”).

142. *Cargill, Inc. v. Monfort of Colorado, Inc.*, 479 U.S. 104, 109 (1986).

143. The FERC held that, because Order No. 888 had removed structural barriers to entry related to transmission, any specific denial of transmission access claims should be resolved directly through enforcement

PPL, the anecdotal approach creates the Catch 22 where a utility cannot present its evidentiary case until each QF is actually in operation but, once that happens, they may be grandfathered under section 210(m), thereby rendering the entire question moot.¹⁴⁴

A change to a structural approach does not mean the Commission would have to remove the mandatory purchase obligation for all small QFs. Order No. 688 drew the line between large and small QFs at twenty MW in 2006 based on the circumstances existing at that time. Today, if the Commission were to reconsider its findings on whether small QFs have access to the market, it could also consider whether a lower threshold would be appropriate. For example, in Order No. 732, the Commission established a threshold of one MW to avoid imposing certain PURPA regulations on net metering customers.

2. Avoided Cost Determinations

The second recurring issue is how to apply the avoided cost rules in regions where the mandatory purchase obligation remains in effect (or, for small QFs, in regions where it has been terminated only for larger QFs). This issue is particularly relevant to the pricing for renewable resources that qualify as small power producers. As the California dispute discussed above revealed, there can be significant price differences between a rule that calculates avoided costs based on all sources and one that calculates avoided costs only for sources that qualify for state renewable mandates. The FERC gave California significant latitude by allowing it to perform the latter calculation. This latitude would become particularly important if the Commission were to exercise jurisdiction over sales made by net metering customers. For those net metering customers that qualify as QFs, this approach would mean that they are entitled to effectively the same generation rate that all similarly situated renewable resources receive—whether located behind the meter or not—but not a rate that permits them to avoid transmission and distribution charges.

There are also recurring issues regarding how to calculate avoided costs in the context of organized markets using locational marginal pricing, or LMP. In *Exelon Wind*, the Commission held that LMPs could not be used for the avoided cost calculation in a congested Day 1 market because, *inter alia*,

[t]he problem with [this] methodology . . . is that it is based on the price that a QF would have been paid had it sold its energy directly in the [Energy Imbalance] Market, instead of using a methodology of calculating what the costs to the utility would have been for self-supplied, or purchased, energy 'but for' the presence of the QF or QFs in the markets, as required by the Commission's regulations.¹⁴⁵

of the OATT, not indirectly by refusal to lift the mandatory purchase obligation. Order No. 688, *supra* note 56, at P 53.

144. 145 F.E.R.C. ¶ 61,053 (Moeller and Clark, C., concurring):

It's important that the Commission's standard for rebutting the presumption not be so high as to preclude a utility from successfully making a showing before the QF is fully operational and the utility is obligated to purchase. Such a circular result would not be a reasonable interpretation of the statute or our own regulations. By considering unit-specific information submitted by an applicant, alongside the opportunities available to suppliers through open markets in an RTO, we can prevent this outcome and avoid rendering meaningless the opportunity to rebut the presumption and obtain PURPA relief.

145. 140 F.E.R.C. ¶ 61,152 at P 9 (2012).

This prompted a petition by several states in the Entergy region for guidance on whether Entergy could use LMPs to determine avoided costs once it joined MISO's Day 2 market. The FERC found the petition premature and therefore declined to rule on the issue.¹⁴⁶ The decision has also raised questions in other regions given that multiple states now use LMPs to calculate avoided costs.¹⁴⁷

The *Exelon Wind* case admittedly raised difficult facts, particularly the absence of the “but for” calculation in a Day 1 market that is available in a Day 2 market (where the day-ahead price at the relevant node can supply the “but for” calculation when the QF puts its energy in real time). However, the FERC's statement that it is a “problem” when avoided costs equal the “price that a QF would have been paid had it sold its energy directly [into the market]” is one that is questionable. The fact that avoided costs reflect prevailing market prices is a good thing, not a bad thing. As the FERC held in *Southern California Edison*, “Congress did not intend QFs to have any rate benefit above a market rate level” because doing so “will . . . give QFs an unfair advantage over other market participants (non QFs),” and thereby “will hinder the development of competitive markets and hurt ratepayers.”¹⁴⁸

IV. POLITICAL DISCRETION: WHAT SHOULD THE FERC DO?

The case for protecting markets against the effects of subsidies is relatively clear, but the task of doing is much easier said than done. The Commission has neither the resources nor the political capacity to become the subsidy police for the Nation's electric markets. (“Political” is used here in its traditional form—the art of governing—not its more common usage of advancing one political party's interests over the other.) The FERC must therefore must choose wisely before intervening. But how should it choose? The article offers three general principles to help guide that choice.

The first principle is that of prioritization. The FERC has limited resources and therefore cannot address every market design problem, whether related to subsidies or not. It is therefore critical to focus on the subsidies having the most substantial harmful effects on competitive markets. And the focus should be primarily on *effects*, not intentions or design, to avoid second-guessing the policy choices of states or other regulators. The FERC's province is to regulate markets, not to engage in normative debates over the propriety of subsidies adopted by other

146. *Council of the City of New Orleans*, 145 F.E.R.C. ¶ 61,057 at P 8 (2013).

147. The states that use LMP (either nodal or zonal) to set avoided cost include those contained in the following citations. See, e.g., *Cent. Ill. Light Co.*, No. 06-0071, 2006 WL 3863623 (Ill. Commerce Comm'n Nov. 21, 2006); *U.S. Steel Corp. v. N. Ind. Pub. Serv. Comm'n*, No. 43674, 2010 WL 1502637 (Ind. Util. Regulatory Comm'n Apr. 7, 2010); *In re Application of Detroit Edison Co.*, No. U-16797, 2011 Mich. PSC LEXIS 143 (Mich. Pub. Serv. Comm'n June 16, 2011); *Joint Application of Wis. Elec. Power Co. and Wis. Gas LLC*, No. 5-UR-106, 2012 WL 6707032 (Wis. Pub. Serv. Comm'n Dec. 21, 2012); *In re the Petition of Atl. City Elec. Co.*, No. EE03110943, 2005 WL 3541022 (N.J. B.P.U. Dec. 14, 2005); *In re Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities—2008*, No. E-100, Sub 117, 2009 N.C. PUC LEXIS 732 (N.C. Bd. Pub. Utils. May 13, 2009); *Va. Elec. Power Co.*, No. PUE-2005-00114, 2007 WL 1201558 (Va. State Corp. Comm'n Mar. 21, 2007); *Appalachian Power Co.*, No. PUE-2008-00035, 2008 WL 4829162 (Va. State Corp. Comm'n Oct. 31, 2008); *Niagara Mohawk Power Corp.*, Nos. 94-E-0098 & 94-E-0099, 1999 N.Y. PUC LEXIS 689 (N.Y. Pub. Serv. Comm'n Nov. 17, 1999); *In re Consol. Edison of N.Y.*, No. 96-E-0897, 2000 N.Y. PUC LEXIS 703 (N.Y. Pub. Serv. Comm'n Aug. 7, 2000).

148. 70 F.E.R.C. ¶ 61,215 at 61,676, n.14.

governmental entities. The FERC emphasized this distinction when it initially rejected the renewables carve-out in the New England, holding that “our primary concern stems not from the state policies themselves, but from the accompanying price constructs that result in offers into the capacity market from these resources that are not reflective of their actual costs.”¹⁴⁹

A necessary corollary to the prioritization principle is the recognition that subsidies are not the only problem affecting competitive electricity markets. There are many other issues that merit attention as well. The Commission should therefore prioritize its agenda to focus on substantial market flaws—whether those flaws relate to subsidies or not. One example of this principle is the Commission’s regulation of capacity markets. The Commission has not hesitated to intervene when subsidies have undermined the core objective of capacity markets—sending accurate price signals to maintain sufficient resources to serve load reliably—but it has also acted on multiple occasions to correct other market design flaws that have nothing to do with subsidies (e.g., adopting sloped demand curves and locational capacity prices). This multi-faceted challenge remains a work in progress.¹⁵⁰

The second principle concerns the nature of remedies and, specifically, the notion that any remedies should focus, as much as practicable, on protecting the market, not individual competitors. This principle was mentioned previously in discussing the FERC’s approach to small QFs under PURPA. I suggested there that the FERC’s policy incorrectly focuses on protecting individual firms, rather than on structural conditions in the market. And the same principle applies here: when the FERC identifies a problem that requires a remedy, the remedy should focus, as much as practicable, on restoring the ability of *the market* to send efficient price signals, rather than attempting to counteract one subsidy with another to protect adversely affected individual firms. A good example in this regard is mitigating the capacity bids of subsidized resources (which allows the market to function as it would without the subsidy), rather than allowing subsidized resources to depress prices and then compensating adversely affected generators for the resulting harm. Although the FERC allows such compensation when needed to avoid retirements that threaten reliability, that form of compensation is not used a *generic* market design remedy to the subsidy problem.¹⁵¹

The final principle concerns federal-state comity. Some of the most vexing issues faced by the Commission implicate the division of regulatory authority in our federal system. For the last decade, the FERC has sought, as much as practicable, to work with the states, not against them, in the design and regulation of competitive wholesale markets and this effort has paid many dividends. This does not, however, mean the two sides will always agree and, particularly in the case of mitigating state subsidies in capacity markets, the disagreements can sometimes be sharp. But even in those instances, the Commission has sought to

149. 135 F.E.R.C. ¶ 61,029, 61,170.

150. Notice of Technical Conference, *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, Docket No. AD13-7-000 (June 17, 2013).

151. *Bridgeport Energy, LLC*, 118 F.E.R.C. ¶ 61,243 at P 41 (2007); *Midwest Independent Transmission System Operator, Inc.*, 109 F.E.R.C. ¶ 61,157 at P 291 (2004).

fashion its remedies in a manner that permits the states to pursue their own policy goals (e.g., which resources to prioritize) but without unduly undermining the efficiency of competitive markets upon which all consumers and technologies must depend.

Consistent with the FERC's general approach in these cases, the author would suggest that due respect for state prerogatives should influence primarily *how* the FERC acts when it identifies a substantial market flaw, not *whether* it acts to protect the market. The recurring issue in this regard is the effects of subsidies on the broader regional market. For example, if a state pursues its policy preferences with respect to fuel diversity or renewable energy in a manner that ensures local customers pay the costs of those preferences, then the broader regional market may not be affected and the FERC may have no reason to act. But if those preferences are funded by price suppression that is paid for by generators or otherwise funded by customers in other states, then the FERC, as the federal entity responsible for interstate regional wholesale markets, has a responsibility to consider whether a rule change is necessary to prevent that price suppression.

One future opportunity—and, to be sure, challenge—in this federal-state scheme is associated with EPA's proposed rule to reduce carbon emissions from existing power plants. The EPA proposal is controversial and will face substantial political and judicial challenges. If it ultimately succeeds, the states will have some flexibility on how to implement new limits on carbon emissions but not necessarily all the best tools to do so. This may open the door for state-federal cooperation in the form of wholesale market design changes to facilitate state compliance options that reduce overall costs to consumers. The ISO/RTO Council has supported an approach whereby compliance is accomplished through regional measurement of emissions, which, in most cases, would require wholesale market design changes. There are substantial economic, legal, and practical issues that will test any such cooperative approach to compliance with carbon regulation, but the issue may nonetheless present an opportunity for the FERC to work with the states on the climate change issue.

The other major federal-state issue that remains looming is net metering. It is understandable from a political perspective that the FERC has chosen not to assert jurisdiction over net metering, but, if the states do not limit the effect of the net metering subsidies, the FERC may be called upon to assert jurisdiction. As noted above, if the FERC chooses to assert jurisdiction, it need not enter the field with a heavy hand. Because rooftop solar would still qualify as a small power producer under PURPA, the FERC could continue to defer, where appropriate, to state avoided cost rules for such resources. To be sure, this approach would reduce the net metering subsidy rooftop solar receives in many states, but it is not clear this level of subsidy is sustainable over the long run given the growing cost shifts among customers. It is one thing to "stimulate" a new technology, but, as the recurring saga associated with renewal of the production tax credit reminds us, it is not easy to end subsidies programs once they are created. Over the long run, the industry and consumers will be better off if all customers pay their fair share of the electric grid and all renewable resources compete on a level playing field irrespective of their location with respect to the meter.

V. CONCLUSION

The FERC faces an unenviable task in grappling with the impacts of subsidies on competitive markets. The FERC has no magic wand to make subsidies disappear and, even where it has clear jurisdiction to act, it has limited political capacity to engage in recurring conflicts with the states. This article presents no easy answers because there are none. Rather, its limited purpose is to provide the legal foundation for action in the event such action is deemed necessary and certain core principles to guide that action.