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MOPR Madness

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MOPR MADNESS

Joshua C. Macey & Robert Ward

Synopsis: Five years ago, in his piece on capacity markets, Jay Morrison discussed what he then viewed as the anticompetitive and arbitrary aspects of FERC’s shifting Minimum Offer Price Rules (MOPR) and their interference with private ordering and state policymaking. MOPRs allow administrative bodies, rather than market participants, to determine the minimum price per kilowatt that generators can submit as capacity market bids. Since then, energy regulators have extended MOPRs to an increasing number of market participants, and critiques of these rules have reached a fever pitch. To say that the latest permutation of price mitigation promotes a cure worse than the disease suggests that the latest iterations of the MOPR rule is curing anything at all.

Given the controversy MOPRs have generated, it is worth considering what distortions, if any, MOPRs remedy. The standard defense of MOPRs is that they enable perfectly competitive markets that match physical power flows to system needs. At different points in the past fifteen years, FERC has suggested that MOPRs mitigate buyer market power, counteract price suppression, and ensure resource adequacy. Yet on closer inspection, none of these justifications withstands scrutiny. As this Article shows, buyer market power is the only market failure for which MOPRs might be an appropriate remedy. That is because buyer market power creates a market for lemons problem because it threatens to drive independent power producers out of wholesale markets. But even that remains merely a theoretical problem, since FERC has never explained why buyer market power distorts wholesale electricity markets or offered proof that net buyers are exploiting their market power. The reality is thus that MOPRs constitute a step backwards towards the old practice of administrative pricing. In attempting to create ideally competitive markets, FERC has developed a resource procurement process that favors incumbent merchant generators and harms investor-owned utilities, member-owned cooperatives, and state-supported resources.

It is ironic, then, that a market intervention that was designed to support competition is now preventing resources from competing with each other. A superior approach is to break up vertically integrated electric utilities and prohibit the types of contracts that facilitate market power abuses. Alternatively, FERC could bring aggressive enforcement actions against buyers that manipulate electricity markets.

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I. INTRODUCTION

Five years ago, Jay Morrison wrote in these pages that “buyer-side market power mitigation mechanisms”—a controversial policy in which administrative bodies, rather than market participants, determine the minimum price per kilowatt that generators can submit in capacity markets¹—“are incapable of accomplishing the goals for which they were adopted.”² Since then, a number of prominent voices in the energy community have joined Morrison’s critique, including at least three

1. See, e.g., Catherine Morehouse, *PJM MOPR Could Cost Market Consumers up to \$2.6B Annually, Report Finds*, UTIL. DIVE (May 19, 2020), <https://www.utilitydive.com/news/pjm-mopr-could-cost-market-consumers-up-to-26b-annually-report-finds/578183/>.

2. Jay Morrison, *Capacity Markets: A Path Back to Resource Adequacy*, 37 ENERGY L. J. 1, 5 (2016).

FERC Commissioners,³ multiple state public utility commissions,⁴ legal and economic scholars who study electricity markets,⁵ and even grid operators charged with implementing price mitigation rules.⁶ Recent MOPR reforms are expected to cost consumers billions, keep unneeded generation in the market, and impede state decarbonization efforts.⁷ And this opposition to MOPRs seems to have had an effect, as Chairman Richard Glick recently acknowledged that “[t]here’s recognition that the MOPR process in general is just not sustainable.”⁸

But given the strong opposition MOPRs have inspired, it is important to understand why this administrative intervention was initially developed and how it expanded during its short and controversial life. The standard defense of MOPRs is that they allow capital to compete in precisely engineered markets that match

3. For example, in December 2019, FERC Commissioner Richard Glick wrote that an intervention that was ostensibly designed to support competitive electricity markets would “[d]ramatically increas[e] the price of capacity . . . and slow[] the region’s transition to a clean energy future.” Glick was writing about a controversial policy called a “minimum offer price rule” (MOPR). Dissenting from an earlier MOPR Order, Commissioner LaFleur wrote that the Commission’s proposal would enact “the most sweeping changes to the PJM capacity construct since the market’s inception more than a decade ago.” *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 F.E.R.C. ¶ 61,236 (2018) (June 2018 Order). And Chairman Bay registered his concern a year earlier. See *New York State Pub. Serv. Comm’n v. New York Indep. Sys. Operator, Inc.*, 158 F.E.R.C. ¶ 61,137 (Comm’r Bay, concurring) (2017).

4. See, e.g., Catherine Morehouse, *Ditching PJM Capacity Market Could Cost New Jersey \$386M Through 2022, Market Monitor Finds*, UTIL. DIVE (May 15, 2020), <https://www.utilitydive.com/news/ditching-pjm-capacity-market-could-cost-new-jersey-386m-through-2022-mark/577998/> (discussing opposition to the PJM capacity market reforms in New Jersey, Illinois, and Maryland); see also Patrick Skahill, *CT Taking ‘A Serious Look’ at Exiting Regional Power Market*, THE CT MIRROR: ENV’T (Jan. 16, 2020), <https://ctmirror.org/2020/01/16/conn-taking-a-serious-look-at-exiting-regional-power-market/> (quoting Katie Dykes, the Connecticut Commissioner of Energy and Environmental Protection, saying:

We are at the mercy of a regional capacity market that is driving investment in more natural gas and fossil fuel power plants that we don’t want and we don’t need. . . . This is forcing us to take a serious look at the cost and benefits of participating in the ISO New England markets.

5. See, e.g., Danny Cullenward & Shelley Welton, *The Quiet Undoing: How Regional Electricity Market Reforms Threaten State Clean Energy Goals*, YALE J. ON REGULATION (Nov. 8, 2019), <https://www.yalejreg.com/bulletin/the-quiet-undoing-how-regional-electricity-market-reforms-threaten-state-clean-energy-goals/> (arguing that MOPRs “present a serious threat to states’ autonomy over their energy mix”); see also Sylwia Bialek & Burcin Unel, *Efficiency in Wholesale Electricity Markets: On the Role of Externalities and Subsidies*, CESifo Working Paper No. 8673, at 27 (Nov. 2020), <https://papers.ssrn.com/sol3/Delivery.cfm/8673.pdf?abstractid=3727748&mirid=1> (arguing that “generation subsidies do not lead to price suppression in the capacity markets” and that MOPRs “are not supported by economic theory”); Michael Goggin & Rob Gramlich, *A Moving Target: An Update on the Consumer Impacts of FERC Interference with State Policies in the PJM Region*, Grid Strategies, LLC, 2-3, 5-6, 8-9 (May 2020), <https://gridprogress.files.wordpress.com/2020/05/a-moving-target-paper.pdf> (projecting the costs of MOPR reforms in PJM); *Comments of the Institute for Policy Integrity at New York University School of Law re: Cricket Valley Energy Ctr. v. N.Y. Indep. Sys. Operator, Inc.*, FERC Docket No. EL21-7-000, 10 (Nov. 18, 2020) (“Not only is evidence of capacity market price suppression absent from the Complaint, our own analysis of mechanisms underlying electricity markets identifies affirmative evidence that the effects of state policies play out in *energy* markets rather than putting downward pressure on capacity prices.”) (emphasis in original).

6. See, e.g., *Request for Rehearing and Request for Clarification of PJM Interconnection, L.L.C. re: Calpine Corp. v. PJM Interconnection, L.L.C. Decision*, FERC Docket Nos. ER18-1314-000, 4 (Jan. 21, 2020) (PJM, the grid operator charged with serving sixty-five million Mid-Atlantic electricity consumers, complaining that the December 2019 MOPR reform in its region “may have paradoxically unintended consequences over time and may result in less economic efficiency”).

7. See *infra* Part III. See also Morehouse, *supra* note 1.

8. Arianna Skibell, *FERC: Glick Unveils Environmental Justice, Climate Plans*, E&E NEWS (Feb. 12, 2021), <https://www.eenews.net/stories/1063725039>.

physical power flows to system needs.⁹ Buyer-side market power mitigation rules emerged, as the name implies, to prevent net buyers from abusing their market power.¹⁰

Since 2006, price mitigation rules have expanded both in scope and in restrictiveness, applying to ever-more resources and granting energy regulators ever-more control over the terms and conditions of capacity market participation. This transformation occurred in three stages. First, in the mid-2000s, FERC and grid operators created offer floors to prevent net buyers of capacity from manipulating capacity markets, though the Commission did not explain why buyer market power was a problem or offer proof that buyers were abusing their market power.¹¹ Second, in 2011, electricity regulators eliminated screens that ensured that price floors applied only to resources that had both the incentive and the ability to manipulate capacity markets.¹² In that period, FERC continued to cite buyer market power to justify price mitigation rules, though the Commission never explained the connection between state subsidies and buyer market power.¹³ Third, by 2018, buyer-side market power mitigation became something of a misnomer. Recent capacity market reforms treat all revenue that does not originate in FERC-regulated wholesale markets as problematic. At this point, FERC largely abandoned the buyer market power justification and began to argue that MOPRs maintain ideally competitive markets.

The history of MOPRs, in other words, is a story of administrative creep. Early MOPRs claimed to protect competitive electricity markets, and they did so by administratively pricing bids submitted by net buyers of capacity.¹⁴ Today's MOPRs also claim to protect competitive electricity markets, and they do so by

9. *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,211 at PP 103-106 (2008). *See also, e.g., id.* at P 103:

Markets require appropriate price signals to alert investors when increased entry is needed. By allowing net buyers to artificially depress prices, these necessary price signals may never be seen. While a strategy of investing in uneconomic entry and offering it into the capacity market at a low or zero price may seem to be good for customers in the short-run, it can inhibit new entry, and thereby raise price and harm reliability, in the long-run.

10. Net buyers are firms that both buy and sell electricity in wholesale markets, but that purchase more electricity than they sell. Net buyers have an incentive to offer to sell capacity at a loss because doing so can reduce the price they pay for capacity. To date, buyer-side market mitigation rules have only been used in capacity markets. However, as discussed in Part IV, *infra*, the type of market manipulation to which FERC has responded can also occur in energy markets. *See PJM Interconnection, L.L.C.*, 135 F.E.R.C. ¶ 61,022 at PP 75-76, 86, 88-90 (2011).

11. *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 61,331 at PP 1, 105, 140-41 (2006) (approving PJM's MOPR); *Devon Power, L.L.C.*, 115 F.E.R.C. ¶ 61,340, at P 1 (2006) (approving ISO-NE's alternative price rule); *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,211, at P 1 (approving NYISO's net buyer mitigation rules).

12. *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,211, at PP 64-70 (discussing these changes that occurred in 2008 in NYISO).

13. Part I, *supra*, explains how states can, in certain limited circumstances, act as net buyers of capacity. *See also* Delia Patterson & Harvey Reiter, *Chasing the Uncatchable: Why Trying to Fix Mandatory Capacity Markets is Like Trying to Win a Game of Whack-a-Mole*, STINSON LLP 2 (June 2016), <https://www.stinson.com/assets/htmldocuments/Chasing%20the%20Uncatchable.pdf>.

14. *See* Joshua C. Macey & Jackson Salovaara, *Rate Regulation Redux*, 168 UNIV. PA. L. REV. 1181, 1189 n.39, 1244-45, 1249 (2020) (discussing that other elements of wholesale electricity markets contain elements of administrative pricing); William Boyd, *Ways of Price Marking and the Challenge of Market Governance in U.S. Energy Law*, 105 MINN. L. REV. 739, 799-801, 800 n.285 (2020); Joshua C. Macey, *Zombie Energy Laws*, 73 VANDERBILT L. REV. 1077, 1095-96, 1105, 1118-19 (2020).

administratively repricing a significant percentage of resources that participate in east coast electricity markets.

MOPRs have had the opposite of their intended effect. FERC created MOPRs to facilitate the development of precisely engineered markets that match physical power flows to system needs in a competitive procurement process. Yet modern MOPRs disincentivize innovation, force consumers to pay for capacity they do not need, reduce generators' incentive to compete for cheaper labor and more favorable financing, and freeze in a region's generation mix years in advance.¹⁵

Given the outrage prompted by recent MOPR reforms, it is worth considering when, if ever, generator bidding strategies pose a threat to restructured electricity markets.¹⁶ Despite its increasingly aggressive use of MOPRs, FERC has never provided a plausible account of why certain resources should be mitigated. Granted, the Commission has asserted that both buyer market power and state subsidies undermine competitive markets and threaten resource adequacy, but it has not explained how this distortion occurs.¹⁷ To evaluate the legitimacy of price mitigation rules, it is therefore important to develop an account of why and in what ways buyer market power and state subsidies do (or do not) distort competitive electricity markets.

15. We are not the first to critique recent MOPR reforms or to trace the history of buyer side market power mitigation rules. Others have argued that MOPRs raise costs and lead to unjust and unreasonable prices. To date, commentators have focused on the undesirable *effects* of MOPRs—that they are anticompetitive, raise costs, encourage excess capacity to remain in the market, and lead to rates that are both arbitrary and capricious as well as unjust and unreasonable. However, while we share these concerns, our focus in this Article is not on the problems MOPRs generate, but rather on whether MOPRs have any justification at all and when—if ever—MOPRs are resolving a market failure. See *infra* Parts III-IV; see also Morrison, *supra* note 2, at 9-11, 21-22, 27-43 (tracing much of the same MOPR history and arguing (correctly, in our view) that centralized capacity constructs and MOPRs are ill-equipped to meet resource adequacy goals); Patterson & Reiter, *supra* note 13, at 4 (arguing that MOPRs are anticompetitive); Harvey Reiter, Jonathan Schneider, & Abraham Silverman, *Restoring Consensus and Balance to FERC's Market Policies*, 1 E.B.A. BRIEF 16, 16 (Fall 2020), https://www.ebanet.org/assets/1/6/EBA_Brief_-_Volume_1_Issue_2.pdf (proposing that FERC focus on “two core fundamentals: (1) respect for competitive resource adequacy markets (as opposed to the chase for an elusive perfect market); and (2) respect for state demands for a greener grid”); Todd S. Aagaard & Andrew N. Kleit, *A Road Paved with Good Intentions?: FERC's Illegal War on State Electricity Subsidies*, 33 ELEC. J. 1, 3-4, 6-7 (2020) (arguing that MOPR reforms lead to unjust and unreasonable rates); Richard B. Miller, Neil H. Butterklee, & Margaret Comes, “Buyer-Side” Mitigation in Organized Capacity Markets: Time for a Change?, 33 ENERGY L.J. 449, 450 (2012) (arguing that “FERC should not intervene in capacity markets in order to establish what it believes to be a just and reasonable rate”).

16. “Restructured electricity markets” are markets in which service is provided through open competition among electric utilities and their competitors. Throughout the nineteenth century, electricity needs were historically met by vertically integrated utilities that provided generation, transmission, and distribution services. See U.S. GOV'T ACCOUNTABILITY OFFICE, RESTRUCTURED ELECTRICITY MARKETS: THREE STATES' EXPERIENCES IN ADDING GENERATING CAPACITY 1, 5 (May 2002), <https://www.gao.gov/products/gao-02-427>.

17. Today, it seems that FERC is trying to promote an idealized vision of markets in which suppliers compete free of outside influence, though historically, FERC has been more accommodating of state resource goals. If this is indeed FERC's goal, it is a quixotic vision that fails on its own terms. Wholesale electricity markets are highly regulated constructs that provide a structural advantage to certain resources. For more details, see the work of Jacob Mays, who has written extensively on this issue. See, e.g., Jacob Mays, David P. Morton & Richard P. O'Neill, *Asymmetric Risk and Fuel Neutrality in Capacity Markets*, 4 NATURE ENERGY 948, 948-54 (2019), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3330932; Jacob Mays, *Missing Incentives for Flexibility in Wholesale Electricity Markets*, 149 ENERGY POLICY 1, 2-4 (2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3623962.

That is the task this Article takes up. The history of price mitigation in east coast electricity markets presents an opportunity to study (a) when, if ever, price suppression distorts competitive electricity markets, (b) why buyer market power poses challenges for restructured electricity markets, and (c) how state and federal policies should (or should not) be permitted to interact with each other.

Price suppression, caused by vertically integrated utilities that possess market power, does distort competitive electricity markets, but it does so for one—and only one—reason: because it gives vertically integrated utilities the ability, in theory, to engage in predatory pricing.¹⁸ The real concern is that the threat of future market manipulation could prevent independent power producers from entering the market because they know that net buyers will continue to suppress the market clearing price, such that their competitors cannot earn a profit from wholesale market revenues.¹⁹ This is a classic market for lemons problem in which a market failure (here, buyer market power) drives high-quality suppliers to exit the market.²⁰ But whether, and to what extent, this type of behavior is occurring remains an open question, since FERC has never provided any evidence that net buyers are engaging in predatory pricing.²¹

State subsidies do not distort markets in the same way. When a generator receives a payment for providing a service that the state values, it is able to sell electricity and a capacity at a lower price. Assuming the subsidized resource is not a vertically integrated utility, it has no incentive to submit a bid that will not permit it to recover its costs because it does not stand to benefit from selling electricity or capacity at a loss.²² Thus, unlike price suppression caused by predatory pricing strategies, state subsidies do not threaten to drive independent power producers out of wholesale electricity markets. They simply generate a price signal that affects suppliers' behavior. Wholesale markets can easily accommodate such policies.

Buyer-side market power mitigation rules should therefore be used rarely, if ever, and only to mitigate buyer market power. FERC should be cautious about

18. While there is a rich literature on seller market power in wholesale electricity markets, less has been written on buyer market power. See David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 789-94 (2008); David B. Spence, *Naïve Energy Markets*, 92 NOTRE DAME L. REV. 973, 977 (2017); David B. Spence & Robert Prentice, *The Transformation of American Energy Markets and the Problem of Market Power*, 53 B.C.L. REV. 131, 132-33 (2012) (arguing that the securities model is inappropriate for market power abuses in energy markets). See also William Boyd, *Public Utility and the Low-Carbon Future*, 61 U.C.L.A. L. REV. 1614, 1617-20 (2014).

19. See *infra* Part IV. See also Boyd, *supra* note 18, at 1667-69; Michael Milligan et al., *Marginal Cost Pricing in a World without Perfect Competition: Implications for Electricity Markets with High Shares of Low Marginal Cost Resources*, NAT'L RENEWABLE ENERGY LAB. OF THE U.S. DEP'T OF ENERGY: TECH. REPORT NREL/TP-6A20-69076, at v-vi (Dec. 2017), <https://www.nrel.gov/docs/fy18osti/69076.pdf>.

20. See George A. Akerlof, *The Market for "Lemons": Quality Uncertainty and the Market Mechanism*, 84 Q. J. ECONOMICS. 488, 488 (1970).

21. See *infra* Part II. See also Morrison, *supra* note 2, at 31-34.

22. This assumes that the subsidized resource is not a vertically integrated utility. A vertically integrated utility has an incentive to submit below-cost bids, but that has nothing to do with the state subsidy. The utility's incentive is to drive its competitors to exit the market so that it can use its monopoly over transmission and distribution to expand its market share in markets for electricity and capacity. See Macey & Salovaara, *supra* note 14, at 1240-41; U.S. FED. TRADE COMM'N, COMPETITION AND CONSUMER PROTECTION PERSPECTIVES ON ELECTRIC POWER REGULATORY REFORM (July 2000), <https://www.ftc.gov/reports/competition-consumer-protection-perspectives-electric-power-regulatory-reform>.

imposing a system of administrative pricing to mitigate what remains an entirely theoretical problem. And, given the many problems associated with MOPRs, net buyers that are exercising market power should be broken up and prohibited from entering into the types of contracts that facilitate market power abuses.²³ In addition, rather than determine by regulatory fiat which resources are able to participate in capacity markets, FERC should instead bring enforcement actions against electric suppliers that abuse their market power. A second-best solution would be to scale back MOPRs so that they apply only to firms that have both the incentive and ability to abuse their market power, as was the case in the mid-2000s.

This Article proceeds in five parts. Part II provides background on electricity markets. Part III traces the history of buyer-side market power mitigation rules in east coast electricity markets. It shows how rules that were originally intended to protect markets from buyer market power have evolved into a system of administrative pricing in markets that are designed to determine resource entry and exit. It also describes the narrow circumstances in which states are capable of manipulating capacity market prices. Part IV explains how price mitigation rules are generating unnecessary costs, leading to oversupply, and impeding state decarbonization efforts. Part V responds to FERC's arguments about why MOPRs do not in fact prevent all resources from selling electricity at their preferred prices. Part VI argues that buyer market power poses a distinct market for lemons problem, that preventing net buyers from abusing their market power is the only legitimate justification for price mitigation rules and explains how recent decisions to expand price mitigation rules exceed FERC's delegated authority.

II. A HISTORY OF PRICE MITIGATION RULES

FERC has always thought of price mitigation as a tool that can encourage the development of competitive electricity markets. However, when FERC, PJM, and ISO-NE first developed these rules in 2006, they argued that buyer market power—and only buyer market power—was what distorted wholesale markets, though neither the Commission nor the grid operators explained why buyer market power presented an existential threat to competitive electricity markets.²⁴ Today, however, the three east coast grid operators treat price suppression as inherently problematic—regardless of whether it was caused by market manipulation or by state subsidies. This Part first explains why price mitigation rules emerged and how they function. The next Part describes the history of price mitigation rules in PJM, NYISO, and ISO-NE.

A. *Restructured Electricity Markets*

In the United States, policymakers have traditionally treated the generation, transmission, and distribution of electricity as a natural monopoly. Regulators granted utilities exclusive franchises and instructed them to provide nondiscriminatory service at regulated rates. In the latter half of the twentieth century, state

23. Our concern is with large distribution utilities that are in a position to exercise market power, not with small government utilities or rural co-ops.

24. *PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61,331, at PP 3, 23 (2006); *Devon Power LLC*, 115 F.E.R.C. ¶ 61, 340, at PP 27, 45, 83, 121-123, 135-137, 145-147 (2006). See also *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,211, at P 1 (NYISO followed suit in 2008).

and federal policymakers in much of the country engaged in a concerted effort to expose generators to market forces.²⁵

By the mid-2000s, however, just as market participants were adjusting to a restructured electricity sector, regulators became concerned that competitive markets were not creating a strong enough price signal.²⁶ They worried that not enough new generation was being built to meet demand.²⁷ Regulators and grid operators felt that they needed to develop additional revenue sources to incentivize construction of new generation. PJM, NYISO, and ISO-NE created capacity markets to meet the expected revenue shortfall in their regions.²⁸

Capacity markets compensate generators for being available to provide electricity.²⁹ This contrasts with energy markets, which compensate generators for selling electricity.³⁰ In energy markets, grid operators determine how much electricity is needed to meet demand, and they dispatch the generators that are able to meet that demand at least cost.³¹ If, for example, four generators each offer to sell 100 MWh of electricity and only 300 MWh are needed to meet demand, the grid operator will dispatch the three generators that submit the lowest bids. Each generator is paid the price offered by the highest bidder to clear. Thus, if one generator offers to sell 100 MWh for \$200, another for \$400, another for \$1,000, and another for \$2,000, and only three generators are needed to meet demand in that period, then the first three generators will clear the market. The three generators that clear the energy auction will each receive \$1,000 for selling 100 MWh of electricity.³² The generator that offered to sell 100 MWh of electricity for \$2,000 will not be paid and will not provide electricity in that time period.

25. These changes can be traced to a rich scholarly debate critiquing rate regulation. See Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052, 1052 (1962); William J. Baumol & Alvin K. Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, 1 BELL J. ECON. & MGMT. SCI. 162, 163 (1970); Alvin K. Klevorick, *The Behavior of a Firm Subject to Stochastic Regulatory Review*, 4 BELL J. ECON. MGMT. SCI. 57, 60-68 (1973); Paul L. Joskow, *The Determination of the Allowed Rate of Return in a Formal Regulatory Hearing*, 3 BELL J. ECON. & MGMT. SCI. 632, 633-34 (1972) (describing the challenges public utilities commissioners face in determining a proper rate of return in light of informational asymmetries). For an excellent history of restructuring, see also Harvey L. Reiter, *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation Under the Federal Power and Natural Gas Acts*, 18 LAND & WATER L. REV. 1, 1-3 (1983); Macey & Salovaara, *supra* note 14, at 1194-1203.

26. Peter Cramton & Steven Stoft, *The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem*, WHITE PAPER FOR THE ELEC. OVERSIGHT BD. 43-46, 60-61 (Apr. 25, 2006), <http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-market-design-for-resource-adequacy.pdf>.

27. *Id.* at 31-39.

28. 117 F.E.R.C. ¶ 61,331 at PP 12, 14-19; 115 F.E.R.C. ¶ 61,340, at PP 1-2.

29. Sylwia Bialek & Burcin Unel, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms*, INST. FOR POLICY INTEGRITY N.Y. UNIV. SCH. L.: ELEC. POLICY INSIGHTS, at 4 (Apr. 2018), https://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.

30. *Id.* at 3-4.

31. *Id.*

32. Bialek & Unel, *supra* note 29, at 4-6; see also INDEP. SYS. OPERATOR N.E., DAY-AHEAD AND REAL-TIME ENERGY MARKETS (2021), <https://www.iso-ne.com/markets-operations/markets/day-ahead-and-real-time-energy-markets/> (noting that, in reality, there are day-ahead markets and real-time energy markets (markets that allow resources to buy and sell electricity in real time), where most resources submit bids a day in advance).

Generators in energy markets typically will bid their marginal costs of production.³³ If a generator offers to sell electricity for less than its marginal costs, it risks being dispatched when the costs of generating electricity exceed the revenue it receives from the energy market.³⁴ If it offers to provide electricity for more than its marginal costs, it risks not being dispatched at times when the clearing price is high enough for the generator to make a profit selling electricity.³⁵

In theory, energy markets can create an adequate incentive for new generators to enter the market when they are needed.³⁶ Although most generators have an incentive to bid their marginal costs, that does not apply to peaking plants (also known as “peakers”), which operate when demand is high.³⁷ These plants generally have high operating costs and operate only a few hours a day. In some cases, they operate only a few times a year.³⁸ Since peakers provide electricity when supply is scarce, they can submit above-marginal-cost bids.³⁹ Peakers are not concerned that they will be displaced by power plants with more expensive operating costs, because there are few, if any, other generators in the market that could displace them.⁴⁰ They can therefore set the market clearing price, which creates an incentive to submit very high bids.⁴¹ The revenue generated in those periods is theoretically sufficient to induce market entry.

However, peakers can also exercise market power. The ability to drive energy prices to very high levels can—and has—led market participants to devise strategies to manipulate energy market prices.⁴² To prevent peakers from manipulating energy markets, every grid operator in the United States has implemented offer caps to limit the price at which generators can offer to sell electricity in energy markets.⁴³ In that way, offer caps limit the ability of peakers to raise prices during scarcity conditions and thus disincentivize manipulative behavior.

But offer caps introduce inefficiencies of their own. In limiting the amount of money that generators can earn in energy markets, offer caps can prevent

33. Marginal costs are the costs a firm incurs for producing one additional unit of a product or service. In electricity, those costs consist primarily of operating costs and fuel costs. OFFICE OF ELEC. DELIVERY & ENERGY RELIABILITY, U.S. DEP'T OF ENERGY, *United States Electricity Industry Primer*, (July 2015), <https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf>.

34. Milligan et al., *supra* note 19, at 23-25.

35. Bialek & Unel, *supra* note 29, at 4 n.11.

36. Paul L. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, 16 UTIL. POLICY 159, 159-60, 159 n.1 (2008); William W. Hogan, *On an “Energy Only” Electricity Market Design for Resource Adequacy*, SCHOLARS OF HARVARD (Sept. 23, 2005) (unpublished manuscript), https://scholar.harvard.edu/whogan/files/hogan_energy_only_092305.pdf.

37. Bethel Afework et al., *Peaking Power*, ENERGY EDUC. ENCYCLOPEDIA (Sept. 2018), https://energyeducation.ca/encyclopedia/Peaking_power; Hogan, *supra* note 41, at 2-6.

38. Bialek & Unel, *supra* note 29, at 4-5.

39. Milligan, *supra* note 19, at 24-25.

40. Peter Cramton, *Electricity Market Design*, 33 OXFORD REV. ECON. POL'Y 589, 597 (2017).

41. *Id.*

42. See Richard A. Opiel Jr. & Jeff Gerth, *Enron Forced Up California Prices, Documents Show*, N.Y. TIMES (May 7, 2002) (“Electricity traders at Enron drove up prices during the California power crisis through questionable techniques that company lawyers said ‘may have contributed’ to severe power shortages.”).

43. See, e.g., PJM, ENERGY OFFER VERIFICATION FAQ, <https://www.pjm.com/-/media/markets-ops/energy/energy-offer-verification/offer-verification-faqs.ashx?la=en> (describing PJM’s process for complying with FERC Order 831’s offer cap requirements); 16 TEX. ADMIN. CODE § 25.505(g)(6) (setting ERCOT’s system-wide offer cap at \$9,000/MWh).

generators from recovering their fixed and capital costs and deter prospective generators from building new power plants.⁴⁴ Offer caps can therefore prevent generators that are needed to meet demand from entering the market.⁴⁵ This is known as the “missing money problem.”⁴⁶

In the early 2000s, PJM, ISO-NE, and NYISO had all implemented offer caps.⁴⁷ At the same time, they all feared that not enough capacity was expected to enter the market to meet future demand.⁴⁸ FERC and the east coast grid operators developed capacity markets to provide additional revenue that was needed to encourage the construction of new generation.⁴⁹ By compensating generators for being available to provide electricity, capacity markets provide revenue to generators that can commit to supplying electricity—regardless of whether the generator clears the market and actually sells electricity.⁵⁰ In that way, capacity markets ensure that there is enough supply to meet a region’s demand for electricity.⁵¹

In a capacity market, a grid operator determines how much capacity is needed to meet peak demand over a period of time and selects the lowest-cost bidders that are able to meet that demand.⁵² As in energy markets, each generator that clears a capacity auction receives the same compensation for the capacity it provides.⁵³ For example, if a region needs 300 MW of power, and if four 100 MW generators each offer to sell their capacity to the region, then the three least expensive bids will clear the capacity auction and the fourth will not.⁵⁴ Thus, if one generator

44. David Newbery, *Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors* 3, ENERGY POL’Y RESEARCH GRP., (Working Paper No. 1508) (2015), https://www.eprg.group.cam.ac.uk/wp-content/uploads/2015/03/1508_updated-July-20151.pdf.

45. *Id.*

46. James Bushnell, Michaela Flagg & Erin Mansur, *Capacity Markets at a Crossroads*, (Working Paper No. 278) (2017), <https://hepg.hks.harvard.edu/files/hepg/files/wp278updated.pdf>.

47. Final Rulemaking, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 81 Fed. Reg. 87,770 (2016) (codified at 18 C.F.R. pt. 35) (describing offer caps in all six RTOs/ISOs).

48. 117 F.E.R.C. ¶ 61,331, at PP 3-4 (describing conditions that led to development of PJM’s Reliability Pricing Model, including that “the addition of new generating units to the system will lag dramatically behind the anticipated growth in demand”).

49. See 117 F.E.R.C. ¶ 61,331, at PP 1-3; 115 F.E.R.C. ¶ 61,340, at PP 1-15; *New York Independent System Operator, Inc.*, 103 F.E.R.C. ¶ 61,201 at PP 1-10 (2003).

50. Bushnell, *supra* note 46, at 28.

51. Other areas of the country do not use capacity markets. See, e.g. ERCOT, RESOURCE ADEQUACY, <http://www.ercot.com/gridinfo/resource#:~:text=RA%20in%20Texas-Resource%20Adequacy,grid%20reliability%20if%20shortfalls%20occur> (last visited Mar. 3, 2021).

52. PJM, UNDERSTANDING THE DIFFERENCE BETWEEN PJM’S MARKETS, (Mar. 6, 2019) <https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx>.

53. See PJM MANUAL 18: PJM CAPACITY MARKET (May 28, 2020), <https://www.pjm.com/-/media/documents/manuals/m18.ashx>.

54. In reality, capacity markets are more complicated than the examples above. They generally compensate generators for providing an amount of capacity per day while also “derating” capacity such that a generator’s capacity payment reflects the frequency with which it is available to meet peak demand. See, e.g. PJM RELIABILITY PRICING MODEL RESULTS, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx> (PJM BRA Results); ISO-NE FORWARD CAPACITY AUCTION RESULTS, <https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf> (ISO-NE FCA Results); NYISO INSTALLED CAPACITY AUCTIONS RESULTS, http://icap.nyiso.com/ucap/public/auc_view_monthly_detail.do (NYISO).

offers to sell 100 MW of capacity for \$100, another for \$1,000, another for \$10,000, and another for \$20,000, then the first three generators clear the auction. Each is paid \$10,000. The fourth generator does not clear and need not participate in the region's energy market during the capacity commitment period. As in energy markets, generators typically will not have an incentive to submit below-cost capacity bids. If a generator submits a below-cost bid, it risks being forced to operate even if it would lose money doing so. An above-cost bid risks not clearing an auction even when it would be profitable for the generator to operate.

B. The Origins of Buyer-Side Market Power Mitigation Rules

But capacity markets, like energy markets, are vulnerable to market power abuses. Load Serving Entities (LSEs), which purchase electricity from generators and transport it to consumers,⁵⁵ have an incentive to submit artificially low capacity bids. Generators that are owned by LSEs can offset the losses their generators incur *selling* capacity in the form of lower prices their distribution assets *pay* for capacity.⁵⁶ A below-cost bid will displace a more expensive offer that would have been needed to meet the region's capacity needs.⁵⁷ Since the higher-cost bid no longer clears the capacity auction, it no longer sets the clearing price. That, in turn, drives the capacity price down. Since all generators that clear capacity auctions are paid the same price for capacity, below-cost bids that are at the margin reduce the revenue all generators receive from capacity markets and, in that way, reduce the price that the LSE is required to pay for capacity. Preventing this type of market manipulation was the sole purpose of buyer-side market power mitigation rules in the mid-2000s.⁵⁸

Unlike independent power producers, LSEs have both the incentive and the ability to submit below-cost capacity bids. Imagine if, in the example above, a fifth 100 MW generator enters the market and is owned by the LSE that is required to purchase capacity from the capacity auction. Imagine, too, that this generator needs \$15,000 from the capacity market to cover its costs. If it bids \$15,000, it will not clear the market because the \$100, \$1,000, and \$10,000 generators will provide all the capacity that the region needs. If, however, the generator offers to provide capacity for \$0, it will clear the market. The generator will incur a \$15,000 loss, but the generator's \$0 bid will save the LSE \$27,000. That is because the generator's \$0 bid means that the \$10,000 generator is no longer needed. The LSE's generator, the \$100 generator, and the \$1,000 generator can provide all the capacity the region needs. As a result, the LSE's decision to submit a below-cost bid means that the \$1,000 generator—not the \$10,000 generator—will set the clearing price. Without its artificially low bid, the LSE would have paid \$30,000 for capacity. The LSE's below-cost bid means it has to pay only \$3,000. The

55. *New Jersey Bd. Pub. Util. v. FERC*, 744 F.3d 74, 82 (3d Cir. 2014).

56. *Id.* at 101. *See also* 117 F.E.R.C. ¶ 61,331, at P 104 (stating that PJM's MOPR is a "reasonable method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self-supply"); 115 F.E.R.C. ¶ 61,340, at P 113 (finding that ISO-NE's APR will address incentives that new self-supplied capacity may have to depress the auction price).

57. This is only the case if the generator that submitted a below-cost bid would not have cleared the capacity auction if it had submitted a bid that reflected its actual costs.

58. *See Devon Power LLC*, 115 F.E.R.C. ¶ 61,340; *see also PJM Interconnection LLC*, 117 F.E.R.C. ¶ 61,331.

\$27,000 it saves by suppressing the price it pays for capacity offsets the \$14,000 its generator incurs by selling capacity at a loss. Note, though, that the LSE's bid also means that every other generator that clears the capacity auction receives \$1,000 instead of \$10,000. As a result, the LSE's price-suppressive bid will reduce the incentive for new generators to enter the market.⁵⁹

Still, when FERC and grid operators developed price mitigation rules in 2006, they seem to have done so to prevent net buyers from engaging in this type of behavior. For example, in the Order approving ISO-NE's capacity market, FERC expressed concern that net buyers would "artificially suppress the auction's clearing price below the price needed to elicit new entry when new entry is needed."⁶⁰ Similarly, in approving the New York City capacity market,⁶¹ FERC noted that a net buyer could "reduce the market price for capacity and lower the net buyer's total capacity bill."⁶² The Commission further explained that, "[i]f the newly added capacity represents only a portion of the net buyer's total capacity needs, the reduction in the buyer's total capacity bill caused by the lower prices could more than offset the loss on the newly added capacity investment."⁶³

FERC also suggested that buyer market power could create resource adequacy problems. Despite the fact that buyer market power will never lead to a revenue shortfall,⁶⁴ FERC worried that such "artificially depressed prices"⁶⁵ would hinder the ability of the capacity market to send "appropriate price signals to alert investors when increased entry is needed"⁶⁶ and deny market participants a "reasonable opportunity to recover the costs of needed investment."⁶⁷

FERC has never provided proof that net buyers are engaging in this type of predation. It is therefore an open question if net buyers are manipulating capacity market prices, or if this problem is purely theoretical. Still, despite being under-theorized, the Commission's primary concern was initially that net buyers would manipulate capacity markets in order to reduce their own costs and, in that way,

59. When he was a judge on the First Circuit, Justice Breyer expressed concern that aggressive prohibitions on predatory pricing would create more problems than they would solve. *See Barry Wright Corp. v. ITT Grinnell Corp.*, 724 F.2d 227, 234 (1st Cir. 1983) ("The antitrust laws very rarely reject such beneficial 'birds in hand' [an immediate price cut] for the sake of more speculative 'birds in the bush'" [preventing exit and thus preventing increases in price in the future]). Justice Breyer has found support among some prominent antitrust scholars. *See, e.g.* Einer Elhauge, *Why Above-Cost Price Cuts To Drive Out Entrants Are Not Predatory - and the Implications for Defining Costs and Market Power*, 112 YALE L.J. 681 (2003). However, Aaron Edlin has offered a powerful critique of this view, showing that "there is no bird in hand because entry cannot be presumed." *See* Aaron Edlin, *A New Theory of Predatory Pricing*, in RESEARCH HANDBOOK ON THE ECONOMICS OF ANTITRUST LAW, (Einer Elhauge ed., 2012). Edlin asks why an "entrant [that] anticipates being outcompeted or predated post entry would ever . . . enter." *Id.* at 8. Based on that observation, he concludes that the "'bird in hand' view presumes entry, and thus is just as speculative a proposition as the fear of high prices post exit." *Id.*

60. 115 F.E.R.C. ¶ 61,340, at P 115.

61. 122 F.E.R.C. ¶ 61,211, at P 101.

62. *Id.*

63. *Id.*

64. *See infra* Part IV.

65. 122 F.E.R.C. ¶ 61,211, at P 103.

66. *Id.*

67. *Id.* at P 105.

prevent the capacity market from providing sufficient revenue to induce the requisite level of market entry.⁶⁸

III. THE HISTORY OF BUYER-SIDE MARKET POWER MITIGATION RULES

Although the specifics of buyer-side market power mitigation rules vary by region,⁶⁹ they generally set a floor below which resources subject to mitigation cannot offer to sell capacity. For example, if, in the example above, the LSE's generator had been subjected to a \$15,000 price floor, it would have been unable to submit a below-cost bid that suppressed the price of capacity. In that way, price floors prevent net buyers from submitting below-cost bids.⁷⁰

Though similar in many respects, the three eastern RTOs that have adopted buyer-side market power mitigation rules have relied on slightly different approaches since they first began mitigating capacity market bids in the mid-2000s. Despite these differences, all three initially focused on buyer market power, and all three have since begun to focus on promoting ideally competitive markets by mitigating offers from any resource that receives out-of-market support. This Part traces the history of buyer-side market power mitigation rules in PJM, NYISO, and ISO-NE.

A. History of Price Mitigation in PJM

PJM adopted a minimum offer price rule (MOPR) in 2006 to curb buyer market power abuses. Then, in 2011, FERC expanded PJM's MOPR to include resources that receive state subsidies. At the time, the Commission continued to defend price mitigation on the ground that it would curb market power abuses. By 2017, FERC had abandoned the market power justification altogether and began arguing that price suppression is inherently problematic. The Commission did not, however, explain how price suppression distorts the PJM capacity market.

1. The Origins of Price Mitigation in PJM

PJM implemented its MOPR in 2006 when it first created a capacity market. Specifically, PJM adopted a Reliability Pricing Model, which is PJM's name for

68. 115 F.E.R.C. ¶ 61,340 at PP 28, 71, 113 (approving settlement agreement establishing the Forward Capacity Market (FCM) with an Alternative Price Rule (APR) to address market power held by buyers); 122 F.E.R.C ¶ 61,211 at P 100 (accepting, subject to conditions, NYISO proposal for buyer-side mitigation in order to prevent uneconomic entry that would reduce prices in the New York City capacity market below just and reasonable levels); 117 F.E.R.C. ¶ 61,331, at PP 7, 104 (approving settlement concerning PJM's Reliability Pricing Model (RPM) and Minimum Offer Price Rule (MOPR) as a reasonable method of assuring that net buyers do not exercise monopsony power); *PJM Interconnection, L.L.C.*, 128 F.E.R.C. ¶ 61,157, at P 91 (2009) (“The lower prices that would result under MPC’s proposal would undermine the market’s ability to attract needed investment over time. Although capacity prices might be lower in the short run, in the long run, such a strategy will not attract sufficient private investment to maintain reliability. The MOPR is the mechanism that restricts the ability of an LSE from using its position as dominant buyer in the market to suppress market clearing prices for at-risk investors, and is analogous to the way market power mitigation rules restrict dominant at-risk investors from using their market position to raise market clearing prices by creating an artificial scarcity. The MOPR does not punish load, but maintains a role for private investment so that investment risk will not be shifted to captive customers over time.”).

69. Note that ISO-NE did initially adopted a clearing price reset mechanism, not a price floor. *See infra* Part I.B.

70. *PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61,331, at P 103.

its capacity market, because it felt that the region's energy markets had failed to provide sufficient revenue to induce market entry. PJM's MOPR was designed to prevent LSEs from abusing their market power. PJM's MOPR set a minimum bid amount below which resources subject to mitigation could not offer to sell capacity. For example, if a resource was willing to sell 100 MW of capacity for \$10,000, and if the price floor prohibited resources of that type from offering to sell 100 MW of capacity for less than \$15,000, then the resource would have been required to bid \$15,000 despite its willingness to bid \$10,000. If the capacity market ended up clearing at a price that compensated 100 MW generators \$12,000, then the resource would not clear the market. It would, however, have cleared had it been allowed to bid \$10,000.

The 2006 MOPR applied only to net buyers that had both the incentive and ability to suppress capacity prices.⁷¹ Specifically, the price floor did not apply when (1) the offer actually affected the market clearing price (the impact screen),⁷² (2) the seller had a "net short position" (the net buyer screen),⁷³ and (3) the offer was below the bid floor (the conduct screen).⁷⁴ These three screens ensured that PJM only mitigated bids that actually reduced the capacity price, were below the expected costs of constructing a power plant, and were submitted by a bidder that was in a position to benefit from selling capacity at a loss.

The impact screen ensured that the PJM MOPR applied only to bids that could affect capacity prices.⁷⁵ Specifically, if a bid did not suppress the capacity market price by (a) \$25 dollars per MW per day, or (b) more than twenty percent, it was not subject to the PJM price floor. Thus, a below-cost bid that did not in fact benefit the bidder by meaningfully reducing the price it paid for capacity was not mitigated. Such bids harm below-cost bidders but do not affect other market participants. A bid that does not actually affect the clearing price does not reduce the price that LSEs pay for capacity and therefore does not affect other market participants. In such circumstances, an LSE's affiliated generator incurs a loss from selling below-cost capacity but, because the bid does not affect the capacity price, the LSE would not be able to offset the generator's loss by reducing the amount it pays to purchase capacity. And, because the LSE's bid does not suppress the market clearing price, the other generators that clear the capacity auction receive the same revenue that they would have received if the LSE's affiliated generator had not participated in the auction.

The second two conditions served a similar purpose. For example, the net buyer screen exempted from mitigation companies that did not have a financial incentive to suppress capacity prices.⁷⁶ Companies that sell more capacity than they purchase rely on electricity markets to make a profit. They therefore have no incentive to suppress capacity prices to a level that would cause them to incur a

71. *PJM Interconnection, LLC*, 119 F.E.R.C. ¶ 61,318, at PP 165-72 (2007).

72. *Id.* at P 166.

73. *Id.* Specifically, the net short position had to be equal or greater than five or ten percent of the Locational Deliverability Area's reliability requirement.

74. *Id.*

75. *Id.* at PP 167.

76. See 117 F.E.R.C. ¶ 61,331 at PP 103-04; 135 F.E.R.C. ¶ 61,022 at P 75.

loss. For that reason, FERC and PJM felt, in 2006, at least, that they could trust net sellers to determine for themselves their profit-maximizing bid strategy.

The third condition, which exempted from mitigation bids that were above the price floor, allowed net buyers to sell capacity when the grid operator determined that the bid reflected the market price of capacity. Specifically, since 2006, price floors in PJM have been based on a resource's Cost of New Entry (CONE), which represents an administrative assessment of the revenue that a power plant needs in order to recover its capital investment and fixed costs.⁷⁷ To calculate the offer floor, PJM determines the *net* Cost of New Entry (net CONE), which represents the revenue that a generator needs to receive from the capacity market in order to cover its capital investment and fixed costs.⁷⁸ Net CONE is calculated by first determining the CONE for that type of resource and then subtracting the revenue that the resource can expect to make from the energy and ancillary services markets.⁷⁹ For example, if PJM determines that a certain type of resource needs \$1,000,000 a year in order to recover its fixed and capital costs, its CONE will be \$1,000,000. If it can expect to recover \$700,000 from energy and ancillary services markets, its net CONE will be \$300,000.⁸⁰

Notably, both CONE and net CONE are calculated based on asset class—not based on the individual generator's actual costs. Thus, when a combined cycle gas plant is subject to an offer floor, PJM calculates the revenue that it expects is necessary to construct a combined cycle gas plant.⁸¹ If a specific resource's price floor is higher than the price needed to clear a capacity auction, then the resource will not clear—even if, for whatever reason, the resource had been willing to sell capacity for a lower price.

Finally, PJM's 2006 MOPR included two additional qualifications that exempted resources from mitigation. First, the seller was given an opportunity to demonstrate that its offer was cost-justified.⁸² PJM described this process as the

77. See THE BRATTLE GRP., PJM COST OF NEW ENTRY: COMBUSTION TURBINES AND COMBINED-CYCLE PLANTS WITH JUNE 1, 2022 ONLINE DATE 21 (2018) <https://www.pjm.com/~media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx>.

78. PJM and NYISO adopted slightly different price floors. In PJM, the net CONE was 80% of the applicable net asset class CONE. 119 F.E.R.C. ¶ 61,318, at P 166. NYISO, by contrast, gave resources slightly more discretion by setting the floor at 75% CONE. 122 F.E.R.C. ¶ 61,211, at P 107.

79. 117 F.E.R.C. ¶ 61,331, at P 26.

80. These examples are illustrative. The Net CONE value for the 2022/2023 BRA in PJM was \$110,459/ICAP MW-year or \$321.57 UCAP/MW-day based on a Gross CONE of \$135,309/ICAP MW-year and net energy and ancillary services of \$24,851/ICAP MW-year, reflecting the dispatch of a new General Electric Frame 7HA turbine, plus a 10% cost adder. PJM, *2022/2023 RPM Base Residual Auction Planning Period Parameters*, <http://www.pjm.com/~media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-planning-period-parameters-for-base-residual-auction-pdf.ashx> (last visited Mar. 26, 2020).

81. PJM's recent compliance filing provided illustrative average CONE and net CONE estimates for several planned resource types. PJM estimates gross CONE for planned nuclear at \$2,000/MW-day, while net CONE is estimated at \$1,483/ICAP MW-day. For a planned combined cycle resource, PJM estimated an average Gross CONE of \$320/MW-day and net CONE of \$152/ICA MW-day. For intermittent resources, PJM adjusts net CONE values to reflect average output levels. As a result, PJM estimated a gross CONE for planned offshore wind of \$1,155/MW-day and net CONE of \$3,146/ICAP MW-day, based on an expected average output level of 26.0%. *PJM Compliance Filing*, 64-65 (Docket Nos. EL16-49, ER18-1414, EL18-178) (Mar. 18, 2020).

82. In fact, even when the seller was subjected to an offer floor, PJM would conduct a sensitivity analysis to determine if the offer should be increased to a specified alternative default level, with the adjustment taking effect only if the sensitivity analysis showed specific effects on market clearing prices. See *id.* at 171.

unit-specific resource exemption, though the grid operator has since changed the name to resource-specific resource exemption. The unit-specific exemption allows a resource to demonstrate that its bid reflects its actual costs, in which case it is permitted, at least in theory, to submit a bid that reflects those costs.⁸³ Second, resources that received state subsidies were also exempted from mitigation.⁸⁴ The FPA reserves to the states authority to control their own generation assets.⁸⁵ PJM initially refrained from mitigating bids submitted by resources that enjoyed state support in order to accommodate state policy preferences.⁸⁶

In sum, price mitigation in PJM emerged to mitigate market power abuses by net buyers of capacity. Not only did PJM list buyer market power as the singular goal of its 2006 price mitigation rule, but it also included a number of screens that limited mitigation to entities that had both the incentive and ability to manipulate the price of capacity.

2. A Broader View of Market Power Abuses

PJM expanded its MOPR in 2011, and it did so across two dimensions. First, PJM expanded the scope of mitigation by eliminating the impact screen and the net short requirement, and by extending the MOPR to resources that received state support.⁸⁷ Second, PJM made MOPRs more restrictive by revising the conduct screen such that it applied to bids below ninety percent net CONE instead of eighty percent net CONE.⁸⁸

a. Eliminating PJM's Net Short Requirement

In 2011, PJM began to worry about the feasibility of developing a definition of the net short requirement.⁸⁹ PJM and FERC felt that the process of developing a precise definition of “net buyer” was like playing “whack-a-mole.”⁹⁰ The specific problem, according to the Commission, was that “the net-short requirement

83. As Part III shows, it does not appear that the unit-specific exemption has allowed resources to avoid a system of administrative pricing.

84. 2006 RPM Settlement Order, 117 F.E.R.C. ¶ 61,331, at P 104.

85. 16 U.S.C. § 824(b)(1); Matthew Christiansen & Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1363 (2021); Jim Rossi, *The Brave New Path of Energy Federalism*, 95 TEX. L. REV. 399, 413 (2017); William Boyd & Ann E. Carlson, *Accidents of Federalism: Ratemaking and Policy Innovation in Public Utility Law*, 63 UCLA L. REV. 810, 813 (2016); Jim Rossi & Thomas Hutton, *Federal Preemption and Clean Energy Floors*, 91 N. CAR. L. REV. 1283, 1286 (2013).

86. 2006 RPM Settlement Order, 117 F.E.R.C. ¶ 61,331, at P 104.

87. 135 F.E.R.C. ¶ 61,022, at P 101.

88. *Id.* at PP 3, 86 (accepting PJM's proposal to eliminate the net short requirement and the net impact screen); *aff'd* 137 F.E.R.C. ¶ 61,145, at P 61 (2011) (denying rehearing requests). PJM also increased net CONE from eighty to ninety percent. *Id.* at P 66. (“[W]e accept PJM's proposal to raise the conduct screen to 90 percent of Net CONE, from the current 80 percent threshold, as a reasonable level. This level reasonably balances the need to prevent uneconomic entry, the inherent vagaries of cost estimation, and the administrative burdens entailed by having to provide data to justify a generator-specific lower threshold.”).

89. 135 F.E.R.C. ¶ 61,022 at PP 1, 2, 75–79.

90. Delia Patterson and Harvey Reiter first used the phrase “whack-a-mole” to describe FERC's attempts to use MOPRs to fix centralized capacity markets. *See*, Delia Patterson & Harvey Reiter, *FERC Chasing the Uncatchable: Trying To Fix Mandatory Capacity Markets Like Trying To Win Whack-a-Mole*, PUB. UTIL. FORTNIGHTLY (May 2016), <https://www.fortnightly.com/fortnightly/2016/05/ferc-chasing-uncatchable>.

can be gamed, and the evasion can come in a variety of forms.”⁹¹ FERC provided two examples to illustrate how net buyers could suppress capacity prices without triggering the MOPR. First, FERC pointed out that net buyers could rely on bilateral contracts to exercise market power.⁹² Second, FERC was concerned that state subsidies could manipulate capacity markets in a similar manner.⁹³

Though FERC did not fully explain how LSEs could use bilateral contracts to abuse their market power, the Commission was correct that, in limited circumstances, net buyers can use bilateral contracts, particularly contracts for differences, to drive down the cost of capacity. In a contract for differences, a buyer and seller agree that the seller will participate in a market, but the parties agree to pay the difference between the settlement price and the market clearing price. For example, an LSE and a generator might agree that the generator will participate in a capacity market but will receive \$100,000 a year to provide 100 MW of capacity regardless of the market clearing price.⁹⁴ If the capacity market pays 100 MW generators \$80,000, then the buyer will make up the difference and pay the generator \$20,000. But if the capacity market pays 100 MW generators \$120,000, then the generator will remit \$20,000 to the buyer. This contract allows each party to hedge against capacity market volatility by stabilizing the price at \$100,000.

However, contracts for differences can be used to manipulate the price of capacity. These contracts give the seller an incentive to offer to sell capacity for \$0. A \$0 bid will ensure that the seller clears the capacity market and therefore guarantees that, in the example above, the seller will receive \$100,000 for selling capacity. FERC seems to have been concerned that LSEs would enter into contracts for differences not to hedge against price volatility, but rather to lower the price they pay for capacity. Even if the contract guarantees the seller an above-market rate, the LSE might be willing to pay this premium to reduce the price of capacity. Because the seller will receive \$100,000 regardless of the market clearing price, it will bid \$0 to ensure that it clears.

At the same time, the buyer might be willing to enter into the contract—even if it is overpaying for capacity—because, in doing so, it can drive down the price of capacity by ensuring that its counterparty offers to sell capacity for \$0. Because the buyer and seller are not affiliated with each other, PJM’s 2006 MOPR would have exempted the bid from mitigation. Hence FERC’s concern that “the net-short requirement’s narrow focus may enable a net buyer, or an entity acting on behalf of a net buyer, to evade mitigation by structuring a new entry transaction in such a way that achieves the same price-lowering effect without triggering the MOPR.”⁹⁵ In the paper hearing that led up to FERC’s 2011 PJM MOPR Order, the Commission received a number of comments explaining that LSEs could use bilateral contracts to manipulate capacity prices.⁹⁶ The challenge for a regulator

91. 135 F.E.R.C. ¶ 61,022, at P 88.

92. *Id.* at P 204.

93. *Id.* at P 187.

94. *See, e.g.*, N.J. Bd. Pub. Util. Final Proposed Form Standard Offer Capacity Agreement § 4 (Mar. 1, 2011), <https://www.nj.gov/bpu/pdf/energy/FinalProposedFormSOCA.pdf>.

95. *PJM Interconnection, LLC*, 119 F.E.R.C. ¶ 61,318, at PP 87–88.

96. For example, PJM pointed out “that a buyer wishing to reduce the clearing price below a competitive level for the benefit of its load could achieve that result through the terms of its power purchase agreement with the new entrant, even though the buyer is neither the seller nor an affiliate of the seller.” *Id.* at P 87. According

is therefore to distinguish between legitimate price hedges and illegitimate attempts to manipulate the price of capacity.

FERC also worried that state subsidies could be used to manipulate capacity markets. The Commission explained that “the net-short requirement allows a state-supported seller that does not itself serve load to make an uncompetitively low offer that will not trigger the MOPR, as the seller would not be in a ‘net-short’ position.”⁹⁷ It is not immediately clear from FERC’s statement how state subsidies generate the same problems as market manipulation by net buyers.⁹⁸ By definition, state subsidies provide a separate source of revenue that allows subsidized resources to submit lower capacity market bids. State subsidies reduce the price all resources pay for capacity. When new entry is needed, the price of capacity will increase, which will prompt new suppliers to enter the market.⁹⁹ As Part V explains, that type of price suppression is valuable, even absent environmental goals, because it means that the price of capacity declines.

The most generous interpretation of the Commission’s decision to eliminate PJM’s net buyer requirement is that FERC believed that doing so was necessary to prevent LSEs and states from manipulating capacity market prices, though, as Part V explains, unlike net buyers that wield market power, states have neither the incentive nor the ability to use contracts for differences to manipulate wholesale prices. That is perhaps the best explanation of the Commission’s cryptic assertion that “the net-short requirement allows a state-supported seller that does not itself serve load to make an uncompetitively low offer that will not trigger the MOPR, as the seller would not be in a ‘net-short’ position.”¹⁰⁰

It thus appears that, by 2011, FERC believed that states had an incentive to manipulate capacity market prices, even though states by definition cannot take a net-short position (states, after all, technically are not buyers of capacity).¹⁰¹

to the grid operator, “[s]uch a buyer could simply commit to cover the seller’s costs and direct in the contract that the seller offer the new plant’s capacity at a low price, and such a transaction would not trigger the current MOPR.” *Id.*

97. *Id.*

98. Part III explains how a contract-for-difference, the contract used in these transactions, actually does generate unique problems and can be understood as an attempt by states to manipulate capacity markets. But the Commission did not explain this reasoning in this Order.

99. See INST. FOR POLITICAL INTEGRITY AT N.Y. UNIV. SCHOOL OF LAW, *Comments on PJM MOPR Filing*, (Oct. 2, 2018), https://policyintegrity.org/documents/Policy_Integrity_Comments_EL18-178.pdf.

100. In fact, FERC received a number of comments that likened state contracts for differences to market manipulation by net buyers of capacity. For example, the Pennsylvania Commission submitted comments arguing “that [PJM’s] net-short requirement allows a state-supported seller that does not itself serve load to make an uncompetitively low offer that will not trigger the MOPR, as the seller would not be in a ‘net-short’ position.” 135 F.E.R.C. ¶ 61,022, at P 87. P3, involving an industry group that represents independent power producers, explicitly connected state subsidies to buyer market power, pointing to Maryland and New Jersey natural gas subsidies as evidence that “buyer market power has proven to be a recurring and pervasive problem in organized capacity markets.” *Id.* at P 20. The Pennsylvania Public Utility Commission made a similar argument, claiming that the net-short requirement created an “unwarranted loop hole giving a state-supported seller that does not itself serve load the incentive to make an uncompetitively low offer that cannot render the seller net-short.” *Id.* at P 80. The New England Power Generators Association (NEPGA) made a similar observation in arguing against an exemption from mitigation for state-supported resources, arguing that “states are not neutral arbiters but instead represent interests on the buyer side of the capacity market.” *ISO New England, Inc.*, 135 F.E.R.C. ¶ 61,029, at P 114.

101. The PJM Internal Market Monitor appeared to endorse a similar idea in supporting the proposal to eliminate the net-short requirement, arguing that the New Jersey statute circumvented the net-short requirement

However, despite FERC's decision to mitigate all uneconomic entry, regardless of the entrant's incentives,¹⁰² FERC and PJM continued to insist that its concern was ensuring that the MOPR was effective at protecting consumers from buyer market power.¹⁰³ The Commission also insisted that its examples were merely illustrative, and that "the evasion of the net-short requirement can come in a variety of forms, some unforeseen, and attempting to revise this provision to account for those scenarios may simply lead to further opportunities for gaming."¹⁰⁴

The solution, according to FERC and PJM, was to eliminate the net short requirement altogether. The Commission pointed out that it would be irrational for a resource to submit a below-cost bid unless it thereby reduced the price it paid for capacity.¹⁰⁵ This logic persuaded the Commission that it could eliminate the net short requirement without interfering with the behavior of independent generators.¹⁰⁶ The fact that firms had managed to circumvent the net buyer screen convinced FERC that "providing this [net buyer] exemption from the MOPR based on perceived incentives of an entity will be ineffective at protecting against buyer market power."¹⁰⁷ For these reasons, FERC concluded that the net-short requirement was "ineffective and unnecessary."¹⁰⁸

b. Eliminating the Impact Screen

In the same Order, FERC eliminated the impact screen, which had exempted from mitigation bids that did not affect the price of capacity.¹⁰⁹ By 2011, FERC concluded that uneconomic capacity bids could deter generator entry even if the bid did not affect the capacity price.¹¹⁰ The Commission offered two reasons to justify this decision.¹¹¹ First, FERC argued that "even a small change in the

and violated the "spirit and intent of the MOPR, given that the sell offer at issue could in fact be regarded as net-short when taking into account the status of New Jersey ratepayers (the buyers)." 135 F.E.R.C. ¶ 61,022, at P 81.

102. FERC indicates that natural gas and coal are especially vulnerable to price suppression. *See id.* at P 39.

103. *Id.* at P 88.

104. *Id.* at P 90.

105. 135 F.E.R.C. ¶ 61,022, at P 49. As discussed in more detail in Part III, PJM conflated below-cost bids with below-CONE bids. Generators have legitimate reasons to submit below-CONE bids if they have other sources of revenue, whereas below-cost bids are more likely to indicate a market power problem. .

106. *Id.* at P 89.

107. *Id.* at P 88.

108. *Id.* at P 86. This decision was also a response to a complaint submitted by the PJM Power Providers Group (P3), which also proposed eliminating the net short requirement. *See id.* at PP 76-77; 103 F.E.R.C. ¶ 61,201, at PP 28-29.

109. Specifically, PJM did not mitigate capacity market bids unless they decreased the capacity price either by (a) \$25 MW per day, or (b) at least 20%. If a resource failed the conduct screen, PJM would rerun the capacity auction without the resource to determine if the resource actually suppressed capacity prices. The magnitude of price suppression required to trigger PJM's impact screen differed by region because PJM applied a different impact screen to different parts of the market. In some capacity zones, a bid failed the impact screen if it suppressed the price by 20%. In other zones, a bid would not fail the impact screen unless it suppressed the capacity price by 30%. *See* 135 F.E.R.C. ¶ 61,022, at PP 91, 101.

110. *Id.* at P 101 (explaining that eliminating the impact screen would have "the ancillary benefit of simplifying the mitigation process.").

111. FERC offered only eight paragraphs to explain its initial Order and five when it denied petitions for rehearing. *Id.* at PP 101-09; *PJM Interconnection, L.L.C.*, 137 F.E.R.C. ¶ 61,145, at PP 61-64.

clearing price from a below-cost offer can harm competition.”¹¹² And second, the Commission was concerned about “the joint effect of multiple below-cost offers.”¹¹³ FERC explained that “even if one were to accept that a below-market offer with no material effect on prices should not be mitigated because it does no harm, such a position provides no comfort as the combined effects of several such offers might well affect prices.”¹¹⁴

FERC was thus concerned that multiple below-cost bids could displace a resource that otherwise would have cleared the capacity market—and raised the clearing price—if the LSE had not submitted below-cost bids. As with its decision to eliminate the net short requirement, FERC’s decision to eliminate the impact screen was motivated by concern that the test was under-inclusive and failed to deter market power abuses by net buyers of capacity.

c. Conduct Screen

The Commission further limited the discretion afforded to market participants by increasing the conduct screen from 80% to 90% of net CONE.¹¹⁵ PJM argued, and the Commission agreed, that an 80% conduct screen “institutes an unreasonable tolerance for below-cost offers that can evade the MOPR and suppress prices to a considerable degree.”¹¹⁶ Once again, FERC was concerned that the previous mitigation rule failed to curb market power abuses, here claiming that bids that are slightly below net CONE could prevent capacity markets from incentivizing needed market entry. The Commission recognized that “estimating project costs is a complex process and that the PJM-determined estimates are, like all estimates, imperfect.”¹¹⁷ Nonetheless, FERC’s anxiety about buyer market power convinced it that its previous Order had given market participants too much discretion. It therefore accepted ISO-NE’s proposal to increase the conduct screen to ninety percent net CONE reflected “a reasonable balance of interests.”¹¹⁸

On its own, the decision to increase the conduct screen to 90% net CONE might not have had a dramatic effect on the PJM capacity market. After all, until the 2011 Order, the PJM MOPR applied only to net buyers.¹¹⁹ However, by simultaneously eliminating the net buyer requirement and increasing the conduct screen, the Commission left many independent power producers—the entities that are supposed to compete to provide low-cost service—with little discretion to enter the market based on their own assessment of whether it would be profitable for them to participate in the PJM market.

112. 137 F.E.R.C. ¶ 61,145, at P 62.

113. 135 F.E.R.C. ¶ 61,022, at P 106.

114. *Id.*

115. *See id.* at P 66 (“[W]e accept PJM’s proposal to raise the conduct screen to 90 percent of Net CONE, from the current 80 percent threshold.”).

116. 135 F.E.R.C. ¶ 61,022, at P 67.

117. *Id.* at P 68.

118. 135 F.E.R.C. ¶ 61,022, at P 73.

119. *Id.* at P 87.

d. Extending the MOPR to State-Subsidized Resources

PJM's 2011 price floor reforms also extended the MOPR to resources that had previously been exempted from mitigation. Prior to the 2011 filings, PJM's MOPR did not apply to planned resources that were developed in response to state mandates.¹²⁰ PJM and FERC eliminated this exemption because, as discussed above, they concluded that states could manipulate capacity market auctions.

Once the Commission determined that states, like net buyers, had both the incentive and ability to manipulate capacity markets, it extended PJM's MOPR to state-subsidized resources that were able to suppress the price of capacity.¹²¹ The Commission reiterated that "[t]he very purpose of the MOPR . . . is to hinder such uneconomic entry, i.e., to ensure that an offer that may be the result of buyer market power does not clear at its artificially low level, thereby injecting uneconomic supply into the market."¹²² According to the Commission, market manipulation "has the effect of disrupting the competitive price signals that PJM's RPM [reliability pricing model] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity."¹²³

FERC was explicit that its decision to eliminate the state policy exemption was based on its (erroneous) view that states were themselves exercising buyer market power.¹²⁴ Because the Commission was concerned about market power abuses—not price suppression itself—it continued to exempt from mitigation certain facilities that received state support, including wind, solar, and demand response aggregators.¹²⁵ The Commission pointed out that, because these resources are intermittent and have unusual cost structures, they are limited in the amount of capacity that they can sell into the market.¹²⁶ As a result, these resources were "a poor choice for any entity attempting to suppress capacity prices."¹²⁷ Thus, although the Commission extended the PJM MOPR to some resources that received state support, it declined to mitigate resources that could not be used to manipulate capacity market prices.

e. Cumulative Effects of PJM's 2011 Changes

Before 2011, FERC assumed that only resources that had a clear interest in and demonstrated ability to suppress capacity prices should be mitigated. By 2011, FERC expanded the scope of mitigation across a variety of metrics, including the net short requirement, the impact screen, the conduct screen, and the state-mandated exemption, while simultaneously limiting the discretion afforded to resources subject to mitigation.¹²⁸ Note, though, that the 2011 PJM reforms were not designed to shield wholesale markets from state policy preferences or protect an idealized vision of wholesale markets in which resources compete free of

120. *Id.* at P 124.

121. *Id.* at P 139.

122. *Id.* at 104.

123. 137 F.E.R.C. ¶ 61,145, at P 3.

124. 135 F.E.R.C. ¶ 61,022, at PP 127, 139.

125. *Id.* at P 152.

126. *Id.* at P 153.

127. 137 F.E.R.C. ¶ 61,145, at P 110.

128. 135 F.E.R.C. ¶ 61,022.

outside influence, but rather to serve the more mundane goal of preventing market power abuses by net buyers of capacity. That is why FERC reiterated, time and again, that “[t]he very purpose of the MOPR . . . is to hinder such uneconomic entry, i.e., to ensure that an offer that may be the result of buyer market power does not clear at its artificially low level, thereby injecting uneconomic supply into the market.”¹²⁹

3. From Market Power to Price Suppression

In 2018 and 2019, FERC further expanded the PJM MOPR, determining that PJM should mitigate bids submitted by any resource that received state support.¹³⁰ The Commission abandoned the theory that price suppression was problematic merely as a means of facilitating market power abuses and instead began treating every bidding strategy or state policy that suppressed capacity prices as problematic.¹³¹

Specifically, in June 2018, FERC found that the two capacity market reforms PJM had proposed were unjust and unreasonable.¹³² PJM had already laid the groundwork for FERC’s Order in 2017 when it asked FERC to approve proposed revisions to its capacity market.¹³³ PJM explained that the reforms were needed not to mitigate market power abuses, but rather to address “the evolving circumstances presented by resources that receive out-of-market support.”¹³⁴ FERC rejected both of PJM’s proposals, finding that they failed to “protect the integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts caused by out-of-market support.”¹³⁵ For the first time, the Commission did not link price suppression in PJM to market manipulation.¹³⁶ In fact, the Commission expressly rejected the market power justification that had previously formed the basis of FERC’s mitigation orders, stating that “state-subsidized resources—not just entities exercising buyer-side market power—can cause significant price suppression.”¹³⁷

This set the stage for FERC’s December 19, 2019 Order, in which the Commission directed PJM to submit a replacement rate that extended the “old” MOPR

129. *Id.* at P 104; *see also id.* at PP 70, 86 (“We find persuasive PJM’s assertion that the revised 90 percent threshold strikes a reasonable balance between protecting against unreasonable exercises of market power and recognizing the imperfection of administrative estimates and the burden of the cost justification process.”) (“We accept PJM’s proposal to eliminate the net-short requirement. The purpose of this provision is to focus the MOPR on entities with the incentive to exercise buyer market power.”).

130. *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 F.E.R.C. ¶ 61,236, at P 5 (2018) (“Although the role of the MOPR, in PJM, originally was limited to deterring the exercise of buyer-side market power, its role subsequently expanded to address the capacity market impacts of out-of-market state revenues.”) (citing 135 F.E.R.C. ¶ 61,022, at PP 139–43).

131. *Id.*

132. *Id.* at P 6.

133. *Id.* at P 14.

134. 163 F.E.R.C. ¶ 61,236, at P 32. FERC rejected PJM’s MOPR-Ex proposal in part because it provided a categorical exemption for renewable resources developed pursuant to a state Renewable Portfolio Standard (RPS). *See id.* at PP 100, 105 (“PJM’s justifications do not adequately support the disparate treatment between resources receiving out-of-market support through RPS programs and other state-supported resources.”).

135. *Id.* at P 150.

136. *Id.* at P 106.

137. *Id.*

to include virtually all resources that receive non-wholesale market compensation.¹³⁸ The MOPR continued to mitigate new natural-gas fired resources because those resources “remain able to suppress capacity prices.”¹³⁹ What changed was that the Commission determined that the PJM MOPR should now apply to “all new and existing, internal and external, State-Subsidized Resources that participate in the capacity market, regardless of resource type.”¹⁴⁰ Moreover, FERC defined subsidy broadly to mean “[a] direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law.”¹⁴¹

The Commission adopted such an expansive definition of subsidy because it felt that price suppression—whether a result of market manipulation or not—could undermine capacity markets and prevent the PJM market from procuring sufficient resources.¹⁴² FERC explained that all “subsidized resources distort prices in a capacity market that relies on competitive auctions to set just and reasonable rates.”¹⁴³ For that reason, the Commission claimed that it was necessary to mitigate any resource that receives a state subsidy so that the “capacity market [is able] to send price signals on which investors and consumers can rely to guide the orderly entry and exit of economically efficient capacity resources.”¹⁴⁴

The December 2019 PJM MOPR differs from the 2006 and 2011 versions in at least two respects. First, the Commission described price suppression as problematic in its own right and not simply as a means of exercising market power. The Commission has, at different times, offered different explanations of why it is concerned about price suppression.¹⁴⁵ For example, when FERC initially argued that aggressive mitigation was needed in eastern capacity markets (in ISO-NE), it claimed that price suppression undermined “investor confidence.”¹⁴⁶ Then, when FERC rejected both of PJM’s proposals in 2018, it explained that additional mitigation was needed to protect “market integrity.”¹⁴⁷ By December 2019, FERC asserted, without offering an explanation, that state subsidies “reject the premise of the capacity market[s].”¹⁴⁸ In fact, since the FPA reserves to states authority over generation facilities, if any tension does exist, it stands to reason that capacity markets—not state subsidies—are in need of reform.

Second, the 2019 reforms subjected a larger percentage of resources to mitigation than did previous PJM MOPRs. According to Commissioner Glick, the

138. *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 F.E.R.C. ¶ 61,239 at P 2 (2019).

139. *Id.* at P 42.

140. *Id.* at P 50.

141. *Id.* at 67.

142. *Id.* at P 68.

143. 169 F.E.R.C. ¶ 61,239, at P 5.

144. *Id.* at P 41.

145. *Id.* at P 15 (As discussed in Part V, price suppression is only problematic when it is used by net buyers to engage in market manipulation).

146. This phrase appeared in the ISO-NE proceeding, discussed later in this Part. *ISO New England Inc.*, 162 F.E.R.C. ¶ 61,205, at P 21 (2018).

147. 169 F.E.R.C. ¶ 61,239, at PP 15-16.

148. *Id.* at P 17.

“sweeping definition of subsidy . . . will potentially subject much, if not most, of the PJM capacity market to a minimum offer price rule.”¹⁴⁹ By defining “subsidy” to include “any resource that receives any financial support for a state”¹⁵⁰—regardless of whether the subsidy supports a goal that is within the state’s sphere of jurisdiction or was designed to offload costs onto other states—the Commission has ensured that a significant percentage of resources that would like to enter the PJM market will not receive capacity market revenue unless the market price rises above the administratively-determined price floor.

PJM’s 2019 MOPR reform is even more significant in light of the increasing role that capacity markets play in determining resource entry and exit. By design, capacity markets are supposed to make sure that there is sufficient revenue to attract the resources that are needed to ensure the reliable provision of electricity. For example, the Commission has described PJM’s capacity market as creating the “price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources.”¹⁵¹ Similarly, the PJM Market Monitoring Unit (MMU), which is an independent body that conducts periodic reviews of PJM markets,¹⁵² has stated that capacity market revenue plays a “critical role” in covering total costs for certain resources, such as natural gas combined cycle units, in PJM markets.¹⁵³

B. History of Price Mitigation in NYISO

NYISO adopted its own buyer mitigation rule in 2008.¹⁵⁴ Like PJM, NYISO first limited mitigation to net buyers of capacity that had both the incentive and ability to suppress capacity market prices, though over time NYISO has extended mitigation to most resources that submit bids that are below their CONE.

1. The Origins of Price Mitigation in NYISO

NYISO adopted a price mitigation rule in response to concerns that net buyers that distributed electricity to New York City customers would submit below-cost capacity bids to lower the price of capacity, and that such bids would discourage needed generation from entering the market.¹⁵⁵ To prevent this from

149. *Id.*

150. *Id.* at P 15.

151. *Id.* at P 156.

152. See PJM, MARKET MONITORING UNIT, <https://www.pjm.com/committees-and-groups/committees/mmuac>.

153. MONITORING ANALYTICS, LLC, STATE OF THE MARKET REPORT FOR PJM 328 (2020), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume2.pdf (Mar. 12, 2020). Similarly, in 2017, PJM noted that a “diminishing energy market returns for supply resources” had “resulted in a shift to the capacity market for the greater proportion of returns for generating units’ recovery of their total investment costs.” PJM, PROPOSED ENHANCEMENTS TO ENERGY PRICE FORMATION 7, <https://wired.pjm.com/-/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx?la=en>.

154. NYISO, 124 F.E.R.C. ¶ 61,301, at P 8 (2008).

155. *Id.* at PP 2, 3, 4 (describing buyer and seller market power in New York City). As of fall 2020, New York’s BSM applies only in the New York region, though in October 2020, a group of generators requested that FERC expand BSM to the entire state.

happening, NYISO followed PJM's lead in 2008 and imposed a price floor on net buyers of capacity.¹⁵⁶

In 1998,¹⁵⁷ to restructure the power sector, the state of New York ordered ConEd, one of the two utilities that had previously provided both generation and transmission services to virtually all New York City customers,¹⁵⁸ to divest itself of most of its generation assets.¹⁵⁹ New York's goal was to shift away from cost-of-service rate regulation and towards a market in which generators competed with each other to provide low-cost electricity.¹⁶⁰

However, just a year later, ConEd and the New York Power Authority (NYPA), the other large buyer in New York City, each procured 500 MW of capacity via bilateral contracts.¹⁶¹ These acquisitions sparked concern that the two utilities would use their newly acquired generation assets to drive down the price of capacity. As in PJM, the Commission observed that “[l]arge net buyers may have both the incentive and the ability to depress prices through uneconomic entry.”¹⁶² The Commission claimed that this type of market manipulation could undermine the “price signals” needed “to alert investors when increased entry is needed.”¹⁶³ That, in turn, could “inhibit new entry, and thereby raise prices and harm reliability, in the long-run.”¹⁶⁴

NYISO's buyer market power rule was simpler than PJM's. Resources subject to mitigation were required to enter the NYISO capacity auction by offering to sell capacity “at a price at or above the applicable offer floor until their capacity clears 12 monthly auctions.”¹⁶⁵ NYISO set the price floor at 75% net CONE.¹⁶⁶ This meant that, with limited exceptions,¹⁶⁷ net buyers in the New York region could not offer to sell capacity for less than 75% of whatever cost NYISO expected that type of generator to need from capacity markets until they had cleared the capacity market for a year.¹⁶⁸ In NYISO, the price floor applied to all new entry unless (1) the market clearing price in the first year was higher than the offer floor (known as Part A of the NYISO mitigation exemption test), or (2) the average

156. *Id.* at P 21. To this day, NYISO's buyer mitigations rules apply primarily in the New York City area.

157. *Id.* at P 2.

158. 124 F.E.R.C. ¶ 61,301, at P 2.

159. *Id.* at P 2 (“In 1998, Consolidated Edison of New York, Inc. (ConEd) divested most of its generators in three bundles – creating a high degree of market concentration for generation in New York City”).

160. *Id.*

161. *NYISO*, 122 F.E.R.C. ¶ 61,211, at P 5 (2008).

162. *Id.* at P 101 (“A large net buyer could acquire new capacity that is not needed in the market and whose costs exceed the market price. Such an investment would be inefficient, the net buyer would lose money on the capacity, and no rational seller would knowingly make such an investment. But the investment could benefit the net buyer because the additional capacity could reduce the market price for capacity and lower the net buyer's total capacity bill. If the newly added capacity represents only a portion of the net buyer's total capacity needs, the reduction in the buyer's total capacity bill caused by the lower prices could more than offset the loss on the newly added capacity investment. As a result, a large net buyer could have an incentive to make such an inefficient investment.”).

163. *Id.* at 103.

164. *Id.*

165. *NYISO*, 170 F.E.R.C. ¶ 61,121, at P 2 (2020).

166. 122 F.E.R.C. ¶ 61,211, at P 107.

167. *Id.* at P 94 (See *infra* discussion of Special Case Resources).

168. *Id.* at P 98.

post-entry market clearing prices in the first three years after entry is higher than the new unit's entry cost (known as Part B of the NYISO mitigation exemption test).¹⁶⁹

These two exceptions operated like the impact and conduct screens PJM adopted in 2006 and abandoned in 2011.¹⁷⁰ By definition, a bid below the price floor will not affect the market clearing price when the average clearing price is higher than the price floor. Similarly, when the average market clearing price is higher than the unit's cost of entry, then the resource *should* enter the market. The high capacity price signals the need for new generation, and the fact that the unit could recover its costs from the capacity market would indicate that the resource is able to sell capacity at a profit.

As in PJM, FERC's concern was initially limited to net buyers.¹⁷¹ According to the Commission, net buyers are "the only market participants with an incentive to sell their capacity for less than its cost."¹⁷² The Commission reasoned that, unlike net buyers, net sellers would enter the market only when they could expect to make a profit.¹⁷³ Because other market participants had no incentive to offer to sell capacity at a loss, FERC felt that bids submitted by net sellers could be trusted to reflect sellers' actual views about their own costs and the profitability of entering the NYISO electricity market.¹⁷⁴

NYISO also initially did not mitigate bids if it was difficult to calculate the resource's cost of entry or if the resource was unlikely to facilitate market power abuses.¹⁷⁵ To that end, NYISO created an exemption for Special Case Resources (SCRs). Special Case Resources refer to demand response resources, which describe firms that curtail electricity use in exchange for compensation.¹⁷⁶ Special Case Resources used to be permitted to determine for themselves their capacity market bids.¹⁷⁷ For example, when FERC first approved NYISO's MOPR, it pointed out that "[t]here is no basis to establish an offer floor for demand response resources based on the cost of new generation entry because there is not necessarily any connection between net CONE by generation and net CONE by demand response resources."¹⁷⁸ Though the Commission did not go into detail, one can imagine the challenges of examining every single bidder and trying to determine the opportunity costs it incurs in reducing electricity at a given moment. The Commission was therefore correct that "it is not clear, nor is it proposed here, how

169. 122 F.E.R.C. ¶ 61,211, at PP 98, 117.

170. These exceptions have not been abandoned, but FERC has rejected a recent NYISO proposal to modify these exemptions to better accommodate New York's decarbonization goals. See, *NYISO*, 172 F.E.R.C. ¶ 61,206, at PP 4-5, 14 (2020).

171. 122 F.E.R.C. ¶ 61,211, at P 106 ("NYISO must specify in its proposed tariff language that the mitigation of uneconomic entry applies only to net buyers").

172. *Id.*

173. *Id.*

174. See 122 F.E.R.C. ¶ 61,211, at P 106 ("New capacity offered by net sellers of capacity would not profit from this strategy, and so would not enter the ICAP market with uneconomic capacity; it will only enter the market when the market sends the price signal indicating that profit can be earned by entering the market.").

175. *Id.* at P 120.

176. *Id.*

177. 122 F.E.R.C. ¶ 61,211, at P 120.

178. *Id.*

NYISO would determine the cost of SCR [special case resource] entry or if that entry was uneconomical.”¹⁷⁹

2. Tailoring the Rule to Monopsony Abuses

Shortly after instructing NYISO to limit mitigation to net buyers, FERC reversed itself on rehearing and approved NYISO’s proposal to extend buyer mitigation to “all uneconomic entry.”¹⁸⁰ Like PJM, NYISO was concerned that the net buyer requirement was under-inclusive and failed to prevent utilities from manipulating capacity prices.¹⁸¹ Thus, in 2008, three years before PJM eliminated its net buyer requirement, FERC accepted NYISO’s view “that limiting uneconomic entry mitigation measures to net buyers could undermine enforcement because buyers may behave strategically to avoid categorization as net buyers.”¹⁸²

NYISO adopted its buyer-side market power mitigation rule after ConEd and the NYPA entered into bilateral contracts which, as discussed in the previous subpart, could be used to manipulate capacity prices. Both utilities procured long-term capacity contracts for differences. Their counterparties therefore had an incentive to offer to sell capacity for \$0, regardless of the capacity market price. Since the two New York City utilities had entered into precisely the type of contract that could be used to manipulate capacity prices, the Commission was concerned, as it was two years later in PJM, that New York City buyers were behaving strategically to “evade mitigation measures.”¹⁸³

Since 2008, FERC and NYISO have steadily, though unevenly, increased the number of resources that are exempted from NYISO’s buyer side mitigation rule. Since 2008, FERC has issued at least ten Orders directing NYISO to reform its buyer side mitigation power rule.¹⁸⁴ FERC’s first intervention came in March 2008, when the Commission broadly exempted SCRs from mitigation in order to avoid “erect[ing] a barrier to entry of demand response into the markets,” and

179. *Id.*

180. *New York Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,170, at PP 52–54 (2010) (finding that NYISO complied with the Commission’s September 30, 2008 order directing NYISO to reflect its ruling that application of the MOPR should not be limited to net buyers).

181. 124 F.E.R.C. ¶ 61,301, at P 28.

182. *Id.*

183. *Id.*

184. 122 F.E.R.C. ¶ 61,211, at P 120 (exempting SCRs from mitigation); 124 F.E.R.C. ¶ 61,301, at P 41 (determining that SCRs should be subject to mitigation); 131 F.E.R.C. ¶ 61,170, at PP 106-07, 137 (approving NYISO’s definition of mitigation and proposed mitigation period and excluding subsidized resources from mitigation); 150 F.E.R.C. ¶ 61,208, at P 31 (reversing decision to exclude subsidized payments from mitigation); 153 F.E.R.C. ¶ 61,022, at P 105 (denying complaint challenging extension of buyer-side market power mitigation rules to SCRs); 158 F.E.R.C. ¶ 61,137, at P 30 (finding that application of buyer-side mitigation rules to SCRs was unjust, unreasonable or unduly discriminatory); 170 F.E.R.C. ¶ 61,118, at P 19 (denying requests for clarification and rehearing on order denying complaint seeking to extend mitigation to resources retained pursuant to a Reliability Support Service Agreement); 170 F.E.R.C. ¶ 61,119, at PP 36–37 (denying complaint challenging application of buyer-side market power mitigation rules to electric storage resources); 170 F.E.R.C. ¶ 61,120, at P 16 (approving application of buyer-side mitigation rules to SCRs and initiating a hearing to determine whether payments from certain retail-level demand response programs should be excluded from offer floor calculation); 170 F.E.R.C. ¶ 61,121, at P 16 (accepting in part and rejecting in part proposed renewable resource exemption and self-supply exemption rules).

because it lacked a “basis to establish an offer floor for demand response resources.”¹⁸⁵

Just six months later, however, in September 2008, the Commission reversed course and found that “it is appropriate for NYISO’s in-City market mitigation rules to apply to SCRs.”¹⁸⁶ The Commission directed NYISO “to impose appropriate market power mitigation measures when conduct departs significantly from what would be expected under competitive market conditions.”¹⁸⁷ The Commission did not explain why it felt that it was now possible to calculate the cost of entry for demand response resources when, just six months earlier, it had said that it was unable to do so. NYISO and FERC spent two year formalizing a rule that would mitigate SCRs, but in 2011, FERC accepted NYISO’s price floor.¹⁸⁸ At that point, NYISO’s buyer-side market power mitigation had very few exceptions and applied to nearly all resources that entered the New York City capacity market.

NYISO’s expansive buyer-side market power mitigation rule lasted until 2015, when the Commission began directing NYISO to exempt from mitigation resources that lacked either the incentive or the ability to suppress capacity market prices.¹⁸⁹ FERC found that some resources—especially renewables and demand response resources—were unable to suppress capacity market prices.¹⁹⁰ To that end, between 2015 and 2017, the Commission issued three Orders instructing NYISO to exempt such resources from mitigation.¹⁹¹

The first came in February 2015, when FERC instructed NYISO to create a “competitive entry exemption” that would “allow for private investors, relying solely on market revenues, to enter the capacity market unmitigated upon certifying that they are a purely merchant investment, with no out of market subsidy.”¹⁹² This requirement can be understood as a more limited version of the net buyer requirements.¹⁹³ Both net buyer requirements and competitive entry exemptions are supposed to ensure that mitigation is limited to resources that have an incentive to mitigate capacity market prices. However, competitive entry exemptions are more restrictive than net buyer requirements because they mitigate only resources that receive revenue through subsidies or retail markets. Thus, under NYISO’s competitive entry exemption, resources whose revenues depend entirely on wholesale markets are permitted to bid below the price floor, but resources that enjoy revenue streams from other sources, such as from state subsidies or retail markets, remain subject to mitigation.

185. 131 F.E.R.C. ¶ 61,170, at P 44.

186. 124 F.E.R.C. ¶ 61,301, at P 41.

187. *Id.*

188. The Commission rejected a few elements of the NYISO rule. For example, it rejected NYISO’s proposal that resources that reenter the capacity market after a period of absence be mitigated a second time. NYISO amended, and the Commission approved, new performance measurement standards for SCRs a year later. See 124 F.E.R.C. ¶ 61,301, at P 99; *NYISO Inc.*, 135 F.E.R.C. ¶ 61,020 at P 1 (2011).

189. *Consol. Edison Co. N.Y., Inc.*, 150 F.E.R.C. ¶ 61,139 (2015); *Consol. Edison Co. N.Y., Inc.*, 152 F.E.R.C. ¶ 61,110 (2015).

190. 150 F.E.R.C. ¶ 61,139, at P 45.

191. 150 F.E.R.C. ¶ 61,139, at P 2; 152 F.E.R.C. ¶ 61,110, at P 11; 158 F.E.R.C. ¶ 61,137, at P 1.

192. 150 F.E.R.C. ¶ 61,139, at PP 1, 4.

193. *Id.* at P 3.

Shortly after FERC directed NYISO to develop a competitive entry exemption, in October 2015, the Commission instructed NYISO to carve out another exemption for resources such as wind and solar that “have limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices.”¹⁹⁴ Then, in 2017, when the Commission ordered NYISO to adopt a blanket exemption for new SCRs, FERC again explained that mitigation should not extend to resources that “have limited or no incentive and ability to exercise buyer-side market power.”¹⁹⁵

As the Commission explained,

[B]ecause a purely merchant generator places its own capital at risk when it invests in a new resource, any such resource will have a strong incentive to bid its true costs into the auction, and it will clear the market only when it is cost effective. As such, a bid from a merchant project below Net [cost of new entry (CONE)] likely represents the economics of that resource, and if it does not, the resource will not be able to recover its costs. The purpose of the MOPR, however, is not to protect a merchant resource from making a poor investment decision with its own capital.¹⁹⁶

FERC therefore recognized that buyer-side market power mitigation rules substituted an administrator’s view about the cost of entering the NYISO market for the merchant’s assessment of its own costs.¹⁹⁷ To reduce the magnitude of this intervention, between 2015 and 2017, FERC sought to rein in NYISO’s buyer mitigation rule so that resources that were not in a position to exercise buyer market power were able to participate in the NYISO capacity market on their own terms.

In those years, FERC repeatedly argued that it was unnecessary, and perhaps even beyond the Commission’s delegated authority, to mitigate resources that lacked the incentive and ability to manipulate capacity auctions. For example, when FERC created a competitive entry exemption in 2015, the Commission found “that NYISO’s current buyer-side mitigation rules are unjust and unreasonable because they are unnecessarily applied to unsubsidized, competitive entrants who have no incentive to inappropriately suppress capacity market prices.”¹⁹⁸ Similarly, in October 2015, the Commission declared it “unjust, unreasonable, or unduly discriminatory or preferential to apply NYISO’s buyer-side market power mitigation rules to certain narrowly defined renewable and self-supply resources that have limited or no incentive and ability to exercise buyer-side market power.”¹⁹⁹ The Commission explained that its ruling “is consistent with the Commission’s generally-applied minimum offer price rule policy; specifically, that buyer-side market power mitigation rules are intended to address market power exhibited by certain entities seeking to lower capacity market prices.”²⁰⁰ FERC

194. 153 F.E.R.C. ¶ 61,022, at P 2. The Commission also directed NYISO to exempt certain self-supply resources for similar reasons.

195. 158 F.E.R.C. ¶ 61,137, at P 31.

196. 150 F.E.R.C. ¶ 61,139, at P 3 (quoting *PJM Interconnection, L.L.C.*, 143 F.E.R.C. ¶ 61,090, at P 57 (2013)).

197. *Id.*

198. 150 F.E.R.C. ¶ 61,139, at P. 45.

199. 153 F.E.R.C. ¶ 61,022, at P. 2.

200. *Id.* at P 10.

cautioned against “the unnecessary mitigation of resources that derive limited or no benefit from lower prices.”²⁰¹

Thus, for a short period in the mid-2010s, FERC felt that buyer-side market power mitigation rules in NYISO had become excessively intrusive, and it took steps to tailor NYISO’s MOPR to resources that could actually abuse their market power. In fact, as recently 2017, FERC Chairman Norman Bay observed in a concurrence that the label “buyer-side market power” had become “imprecise and somewhat of a misnomer, for it has come to have a broader meaning than what the name might otherwise suggest.”²⁰² Bay argued that “the MOPR suffers from a troubling lack of coherence that calls into question the soundness of its underlying rationale.”²⁰³ He therefore urged the Commission to develop a more coherent approach to buyer-side market power mitigation rules.

3. Abandoning the Market Power Justification

FERC’s attempts to pare back mitigation in the NYISO market proved short-lived. On February 20, 2020, the Commission issued four separate Orders, each of which directed NYISO to expand its buyer-side market power mitigation rule.²⁰⁴ FERC directed NYISO to mitigate the very resources that, just three years earlier, it had found were unable to facilitate market power abuses.²⁰⁵ Among other things, FERC instructed NYISO to impose a cap on the renewables exemption²⁰⁶ and extend mitigation beyond net buyers to demand-side resources that had previously been exempted²⁰⁷ and to storage resources.²⁰⁸

The Commission continued to refer to NYISO’s MOPR as a buyer-side mitigation rule, but the logic it marshaled to defend the 2020 reforms suggests that the FERC has become more concerned about price suppression than market power. In all four Orders, FERC explained that its primary concern is “protect[ing] the capacity market from the price suppressive effects of resources receiving out-of-market support.”²⁰⁹ Although the Commission asserted that its decision recognized “the need to protect NYISO’s ICAP markets from the potential for SCRs to exercise buyer-side market power,”²¹⁰ FERC did not discuss whether SCRs are buyers at all—in fact, the Order mitigates bids submitted by net sellers as well as bids submitted by net buyers—and instead is based entirely on the ability of SCRs

201. 158 F.E.R.C. ¶ 61,137, at P. 30.

202. 158 F.E.R.C. ¶ 61,137 (Bay, Comm’r, concurring).

203. *Id.*

204. *See* 170 F.E.R.C. ¶ 61,118; 170 F.E.R.C. ¶ 61,119; 170 F.E.R.C. ¶ 61,120; 170 F.E.R.C. ¶ 61,121.

205. *Compare* 158 F.E.R.C. ¶ 61,137, *with* 170 F.E.R.C. ¶ 61,118.

206. *New York State Public Service Commission, et al. v. New York Independent System Operator, Inc.*, FERC Docket No. EL16-92.

207. 170 F.E.R.C. ¶ 61,119.

208. *Id.*; FERC also declined to expand the NYISO buyer-side mitigation rule to resources that are retained for reliability reasons. *See Indep. Power Producers of New York, Inc. v. New York Indep. Sys. Operator, Inc.*, F.E.R.C. ¶ 61,214 (2015).

209. *New York State Pub. Serv. Comm’n and New York State Energy Research and Dev. Auth. v. New York Indep. Sys. Operator, Inc.*, 170 F.E.R.C. ¶ 61,119, at P 37 (2020).

210. *New York State Pub. Serv. Comm’n v. New York Indep. Sys. Operator, Inc.*, 170 F.E.R.C. ¶ 61,120 at P 19 (2020).

to suppress capacity market prices.²¹¹ Nor did the Commission explain why resources that it had previously declared unable to manipulate capacity markets should now be subject to mitigation.

While the Commission's NYISO Orders have proceeded haphazardly, over the past decade, NYISO's buyer side mitigation rule has extended to resources that, by the Commission's own admission, cannot be used to manipulate capacity market prices. Unlike PJM, NYISO adopted a highly restrictive buyer mitigation rule as early as 2008. The Commission then narrowed the scope of mitigation in 2015, and again in 2017, because it felt that the NYISO buyer mitigation rule was being applied to resources that could not be used to manipulate capacity market prices. The Commission reversed course in February 2020, expanding the scope of NYISO's buyer market power rule and mitigating the very resources that the Commission had previously stated were unlikely to facilitate market power abuses.²¹² And, in October 2020, two gas generators filed a complaint against NYISO asking FERC to increase the restrictiveness of buyer side mitigation and extend the price floor to the entire state.²¹³ In NYISO, as in PJM, the Commission now treats price suppression as problematic in its own right and not because it can occasionally enable market power abuses.

C. History of Price Mitigation in ISO-NE

While NYISO and PJM have relied on MOPRs to mitigate buyer market power since they first adopted capacity markets, ISO-NE originally relied on a different mechanism to address buyers' incentive to submit below-cost-capacity bids. Over the past decade, however, ISO-NE's buyer-side market power mitigation rule has converged with its neighbors in New York and the mid-Atlantic.²¹⁴

1. ISO-NE's Alternative Price Rule

In 2006, the same year FERC approved PJM's capacity market, ISO-NE adopted something called an Alternative Price Rule (APR) to prevent net buyers from abusing their market power.²¹⁵ This rule was triggered when new capacity sought to enter the market at a price below the administratively-determined CONE (known as the "reference price").²¹⁶ But rather than administratively reprice *bids*

211. *Id.* at P 20; *see also id.* at P 1 (Glick, Comm'r, dissenting) ("Today the Commission issues a series of orders addressing buyer-side market power mitigation rules in the NYISO capacity market. Notably, none of the orders is actually focused on buyers with market power.").

212. *See Calpine Corp. Dynegy, Inc., v. PJM Interconnection, LLC*, 169 F.E.R.C. ¶ 61,239, at P 161 (2019).

213. *See* FERC Docket No. EL21-7-000 at 1, 35 (Oct. 14, 2020).

214. *Devon Power LLC*, 115 F.E.R.C. ¶ 61,340, at P 113. Again, though, the buyer-side market power mitigation rule was designed to prevent LSEs from submitting bids that would "reduce the prices they must pay for existing capacity procured in the auction." *Id.*

215. *Id.* at PP 109-110.

216. *Id.* at P 17. Technically, ISO-NE subtracted a cent from that price at which the last bid from new capacity was withdrawn minus one cent or CONE, whichever was lower. As in NYISO, this was 75% of CONE. *Id.* at P 109 ("The rule applies when at least some of the offers from new capacity or imports are below .75 times CONE and the Market Monitor concludes that such low offers are not consistent with long run average costs, opportunity costs, or other reasonable economic measures. Capacity submitting such bids is deemed to be "out-of-market." When any submitted bids are deemed out-of-market, the capacity clearing price will be reset when the following conditions are met . . . If these conditions are met, the clearing price for the applicable capacity

submitted by resources subject to mitigation, the APR administratively reset the clearing price.²¹⁷ ISO-NE would thus reset the capacity market clearing price when “(1) new capacity is needed, either system-wide or in an import-constrained zone; (2) there is adequate supply in the auction; and (3) at the auction clearing price, purchases from ‘out-of-market’ capacity are greater than the required new entry.”²¹⁸ “Out of market” resources (ISO-NE uses the acronym OOM to describe them) describe all resources that receive a payment outside of ISO-NE’s energy, capacity, and ancillary services markets.²¹⁹ OOM resources include resources that offer to enter ISO-NE’s capacity market at a price that is below those resources’ long-run average costs.²²⁰ ISO-NE’s internal market monitor, which is a department within ISO-NE, determines whether a resource receives out of market compensation. Absent a mitigation rule, resources that received state subsidies or that had entered bilateral contracts with an LSE were able to factor those revenues into their capacity bids. Thus, ISO-NE’s APR was triggered only when ISO-NE faced a capacity shortfall and when OOM resources were sufficient to meet that shortfall.

The APR reset the clearing price to the price at which the market would have cleared had the mitigated bid not participated in the capacity auction.²²¹ If, for example, a net buyer submitted a bid that caused the clearing price to decline from \$100,000 per 100 MW of capacity to \$50,000 per 100 MW of capacity, the APR would reprice the capacity clearing price to \$100,000.²²² By setting a new price for capacity, ISO-NE’s APR removed the incentive for resources to manipulate ISO-NE’s capacity market.

While ISO-NE did not, as NYISO and PJM did, include a net buyer requirement that limited the capacity repricing rule to net buyers, the rule was designed such that only net buyers would be affected.²²³ In fact, when FERC accepted the *Devon Power* settlement, it explained that the APR was designed to prevent net buyers—and only net buyers—from abusing their market power:

zone will be set to the lower of 1) the price at which the last bid from new capacity was withdrawn, minus \$0.01 or 2) CONE.”)

217. *Id.* at P 109. Of course, in one sense price floors also reprice the capacity market clearing price, because the decision to exclude a less expensive bid and replace it with a more expensive bid increases the clearing price. *See also id.* at P 19.

218. *Devon Power, LLC*, 115 F.E.R.C. ¶ 61,340, at P 109. The first condition was if the Installed Capacity Requirement (ICR) exceeded the amount of existing capacity. The second condition was met when the total amount of capacity offered into the FCA at the beginning of the auction was adequate to meet the ICR. The final condition was met when the amount of out-of-market capacity exceeded the need for new capacity and no new capacity cleared the market. *See ISO New England, Inc. & New England Power Pool Participants Committee*, 131 F.E.R.C. ¶ 61,065, at P 38 (2010).

219. 131 F.E.R.C. ¶ 61,065, at P 7.

220. *See* ISO-NE, INTERNAL MARKET MONITOR, <https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/>.

221. *Id.* at P 16. *Specifically*, ISO-NE reset the price such that it equaled the lower of (1) the estimated cost of entry, or (2) the amount bid by a generator not affiliated with the LSE that would have cleared but for the LSE’s price suppressive bid. *See id.* at PP 84, 86.

222. *Id.* at P 39. *Technically*, ISO-NE would reprice the clearing price to the lower of \$99,999.99 or the net CONE for that resource.

223. 131 F.E.R.C. ¶ 61,065, at P 76; *See also* 169 F.E.R.C. ¶ 61,239, at PP 6, 23; 115 F.E.R.C. ¶ 61,340, at P 153.

In the absence of the alternative price rule, the price in the FCA could be depressed below the price needed to elicit entry if enough new capacity is self-supplied (through contract or ownership) by load. That is because self-supplied new capacity may not have an incentive to submit bids that reflect their true cost of new entry. New resources that are under contract to load may have no interest in compensatory auction prices because their revenues have already been determined by contract. And when loads own new resources, they may have an interest in depressing the auction price, since doing so could reduce the prices they must pay for existing capacity procured in the auction.²²⁴

To understand how the APR deterred market manipulation, imagine that two resources submit bids below their net CONE. One is affiliated with an LSE and the other is an independent generator that believes it can construct a power plant for less than whatever price ISO-NE's market monitor calculated to be that resource's CONE. The APR would disincentivize the LSE from submitting a below-cost bid because, by administratively increasing the price of capacity, the APR would force the LSE to pay the amount that it would have had to pay absent a bid from its generator. Generators that relied on capacity market revenues would benefit when the APR raised the price of capacity because doing so would increase the revenue they earned from the capacity market. Thus, while ISO-NE's APR initially differed from the MOPRs adopted in PJM and NYISO, it, too, was designed to prevent market power abuses by net buyers of capacity.²²⁵

2. Buyer-Side Market Power and Price Suppression

ISO-NE's APR lasted less than four years. Just two years after FERC instructed ISO-NE to develop an APR, a coalition of independent generators filed a complaint arguing that the APR was unjust and unreasonable because it failed to deter resources that received OOM support from clearing the ISO-NE capacity market.²²⁶

FERC agreed, finding that ISO-NE's APR was defective because it failed to mitigate market power abuses.²²⁷ Specifically, FERC determined that the APR would likely never be triggered because OOM resources would enter the market even when the region did not need any additional capacity.²²⁸ In ISO-NE's first two capacity auctions, 4,034 MW of new capacity cleared the market, and ISO-NE's internal market monitor determined that 3,351 MW of the capacity that entered the market was OOM.²²⁹ The entry of so much capacity when the grid operator did not reprice the capacity market price ensured that the region had enough generation to meet the region's demand and therefore forestalled the need to trigger the APR.²³⁰ For that reason, the Commission concluded that "sponsors of

224. *Devon Power, LLC*, 115 F.E.R.C. ¶ 61,340, at PP 27, 113 (explaining that the APR would "address high concentrations of market power.").

225. 115 F.E.R.C. ¶ 61,340, at P 27.

226. *ISO New England, Inc. and New England Power Pool Participants Committee*, 135 F.E.R.C. ¶ 61,029, at 13–20 (2011).

227. *Id.* at P 19.

228. *Id.* at PP 58–59.

229. 131 F.E.R.C. ¶ 61,065, at P 39 ("The APR was not triggered because, in each FCA, the amount of existing capacity exceeded the ICR. In addition, the IMM states that none of the capacity that was identified as OOM affected the prices in the first three FCAs.").

230. *Id.*

OOM resources that represent a large share of the load could circumvent the application of the APR for several years by investing in sufficient OOM resources to maintain a continuous surplus of capacity over that period that avoids the need for new in-market capacity.”²³¹

FERC was therefore concerned that OOM resources would facilitate market power abuses even when the APR was not triggered. The Commission noted that “OOM resources can affect prices even when no new capacity is needed, by displacing what would otherwise be the marginal, price-setting existing resource.”²³² In doing so, “[a] new OOM resource can suppress the market clearing price even when no new capacity is needed, by displacing a marginal existing resource that would otherwise have set the market price.”²³³ This, the Commission claimed, meant that the “existing APR triggering conditions . . . may overlook situations in which an OOM resource may be used as an instrument of buyer market power.”²³⁴ FERC’s concern was supported by ISO-NE’s experience administering the APR. In its short four-year life, ISO-NE never applied the APR.²³⁵

FERC’s fear that ISO-NE’s APR had failed to prevent market power abuses led to a related concern, which was that the entry of OOM capacity would force consumers to pay for capacity they did not need. By increasing the price of capacity, the APR would therefore procure a resource that would otherwise not have cleared. At the same time, because the APR would not prevent the OOM resource from clearing, it would ensure that an additional supplier would clear: the OOM supplier would clear and the resource that cleared only because ISO-NE reset the capacity price would now clear. Only one of these resources was needed, but the APR ensured that both would enter the market. For that reason, FERC determined that ISO-NE’s APR contributed to bloated reserve margins.²³⁶ It explained that “ISO-NE has not offered a persuasive reason why . . . it is just and reasonable to require customers to incur unnecessary costs in order to purchase more capacity than the FCM was established to procure and that is needed for reliability.”²³⁷

Based on these concerns, FERC rejected ISO-NE’s APR and, in 2010, instructed the grid operator to develop a buyer market power mitigation rule “akin to those in PJM and NYISO.”²³⁸ FERC explained that a price floor “would deter the exercise of buyer-side market power”²³⁹ and “spare customers the cost of

231. *Id.* at P 72.

232. *Id.* at P 70.

233. *Id.* at P 76.

234. 131 F.E.R.C. ¶ 61,065, at P 76.

235. *Id.* at P 45.

236. *See ISO New England, Inc. & New England Power Pool Participants Committee*, 135 F.E.R.C. ¶ 61,029 at PP 157–165 (2011).

237. *Id.* at P 163.

238. *Id.* at P 165.

239. *Id.* at P 166. “First, if the offer floor is set at a level that approximates the net cost of entry of a new resource, offer-floor mitigation would deter the exercise of buyer-side market power and the resulting suppression of capacity market prices associated with uneconomic entry. By preventing new resources from offering at prices that are significantly below their true net cost of entry, new resources would not be able to lower the price of capacity significantly below competitive levels. As a result, there would be no financial reward for subsidizing new resources for the purpose of exercising buyer-side market power.”

procuring capacity in excess of the ICR—excess capacity that is not needed to meet ISO-NE’s reliability objectives.”²⁴⁰

Still, FERC continued to justify buyer-side market power mitigation rules as necessary to mitigate buyer market power, reasoning that a price floor would “deter the exercise of buyer-side market power and the resulting suppression of capacity market prices associated with uneconomic entry” by “preventing new resources from offering at prices that are significantly below their true net cost of entry.”²⁴¹

Although FERC ordered ISO-NE to develop a MOPR in 2011, it was not until 2013 that the grid operator proposed, and FERC accepted, ISO-NE’s proposed reforms.²⁴² In February 2013, FERC accepted ISO-NE’s proposal to adopt a price floor.²⁴³ ISO-NE initially created an “asset-class specific minimum offer price rule” that created an “offer review trigger price” (ORTP, which is ISO-NE’s acronym for net CONE) that applied to new resources that sought to enter ISO-NE’s capacity market.²⁴⁴ ISO-NE set the offer review trigger price at 100% of the estimated cost of new entry.²⁴⁵ This meant resources subject to the price floor were not given any discretion whatsoever to deviate from the administratively determined price.²⁴⁶

Although FERC’s 2013 ISO-NE Order was expansive, the Commission quickly recognized that this MOPR was excessively broad, and that it mitigated resources that were not in a position to exercise market power. Thus, as in NYISO, FERC accepted revisions that tailored the rule to resources that could exercise market power.²⁴⁷ To that end, in 2014, FERC accepted ISO-NE’s proposed Renewable Technology Resource (RTR) exemption on the ground that renewables were incapable of exercising market power.²⁴⁸

3. ISO-NE’s Shift Toward Price Suppression

Four years later, however, price suppression replaced market power as the primary reason for mitigating capacity market bids. In 2018, ISO-NE submitted proposed tariff revisions that would include a new capacity auction process, called Competitive Auctions with Sponsored Policy Resources (CASPR).²⁴⁹ Under CASPR, the annual capacity auction would consist of two stages. The first would

240. *Id.* at P 167.

241. 135 F.E.R.C. ¶ 61,029, at P 166. Unlike PJM and NYISO, FERC did not require ISO-NE to develop a test to determine whether a particular resource had the incentive or ability to exercise buyer-side market power, instead simply focusing on whether a resource’s offer could “lower the price of capacity significantly below competitive levels.”

242. *Id.*

243. *Id.* at P 372.

244. 142 F.E.R.C. ¶ 61,107, at P 7.

245. *Id.*

246. *See id.* at PP 15, 39.

247. *Id.*

248. *ISO New England Inc. & New England Power Pool Participants Committee*, 147 F.E.R.C. ¶ 61,173, at PP 83–84 (2014).

249. *See ISO New England, Inc.*, 162 F.E.R.C. ¶ 61,205, at P 1 (2018). In November 2020, FERC denied rehearing while modifying the discussion in the initial CASPR order and reaching the same result. *ISO New England Inc.*, 173 F.E.R.C. ¶ 61,161, at P 2 (2020).

maintain the then-existing process but would extend the MOPR to all resources that received state support.²⁵⁰ At the end of the first auction, ISO-NE would run a substitution auction, which would permit existing resources that acquired capacity supply obligations in the primary auction to “offer a demand bid . . . indicating a willingness to permanently retire from all ISO-NE markets at a certain price.”²⁵¹ Because the MOPR would not apply in the substitution auction, it would allow state-supported resources to “account for out-of-market revenues and offer at the lowest price at which they are willing to accept a capacity supply obligation.”²⁵² The first step excluded every resource that was subject to mitigation. The second step allowed mitigated resources to offer to buy out resources that cleared the market.

When FERC accepted ISO-NE’s proposal, it explained that, “[a]bsent a showing that a different method would appropriately address state policies, we intend to use the MOPR to address the impacts of state policies on the wholesale capacity market.”²⁵³ To a greater extent than the PJM and NYISO MOPRs, ISO-NE seems to be trying to strike a balance between accommodating state policy preferences and mitigating resources that receive out-of-market support. Still, like PJM and NYISO, the Commission has begun to treat non-wholesale market revenues as a threat to ideally competitive markets that should be dealt with through mitigation. The result is a highly complex process that requires new electricity providers to buy out incumbents before they are allowed to enter the market.

Thus, in all three east coast electricity markets, FERC now uses the MOPR to protect some sort of ideal market process and “produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates.”²⁵⁴ Doing so, however, has led to a series of highly intrusive administrative interventions in which an administrative body—not market participants—determines the minimum bid amount that generators can submit in auctions for capacity. As the next part shows, this transformation has turned MOPRs into aggressive interventions that counteract state energy policies.

IV. ADMINISTRATIVE PRICING

The Commission’s recent orders have drawn criticism from FERC Commissioners, clean energy advocates, and state and federal policymakers.²⁵⁵

250. 162 F.E.R.C. ¶ 61,205, at P 7.

251. *Id.*

252. *Id.* at P 9.

253. *Id.* at P 22.

254. *Id.* at P 21.

255. See, e.g., *New York State Pub. Serv. Comm’n v. New York Indep. Sys. Operator, Inc.*, 158 F.E.R.C. ¶ 61,137 (2017) (Bay, Comm’r, concurring) (“Despite the best intentions of the Commission, in my view, the MOPR has turned out to be unsound in principle and unworkable in practice.”); *New England States Committee on Electricity v. ISO New England Inc.*, 142 F.E.R.C. ¶ 61,108 (Norris, Comm’r, and Wellinghoff, Chairman, dissenting) (“ISO-NE chose to broadly apply its MOPR to all new resources. The New England States Committee on Electricity (NESCOE) and others have raised significant concerns about whether this broad application of the MOPR will impinge on legitimate state policy goals. In particular, they assert that such broad mitigation will unfairly inhibit state efforts to diversify their fuel mix and procure new renewable resources.”); SYLWIA BIALEK & BURCIN UNEL, CAPACITY MARKETS AND EXTERNALITIES: AVOIDING UNNECESSARY AND PROBLEMATIC REFORMS 25 (2018) (“[T]he MOPR-Ex would cause all the standard problems that have been raised related to

Commissioner Glick, for example, described the December 2019 PJM MOPR Order as “a bailout, plain and simple” and asserted that “[f]rom the beginning, this proceeding has been about two things: Dramatically increasing the price of capacity in PJM and slowing the region’s transition to a clean energy future.”²⁵⁶ At least four states have announced that they are considering exiting capacity markets altogether as a result of the 2019 PJM MOPR Order.²⁵⁷ And industry analysts have estimated that these mitigation rules will cost consumers billions of dollars a year.²⁵⁸

Given the stakes of these orders, it is worth considering how, precisely, MOPR reforms have undermined competitive electricity markets. The Commission has justified MOPR reforms as necessary to preserve “market integrity”²⁵⁹ and protect “investor confidence.”²⁶⁰ In reality, however, FERC’s orders do just the opposite. They are restoring elements of the administrative pricing system that used to characterize the electric power system. In doing so, they are leading to higher electricity prices, causing excess capacity to remain in the market, stifling innovation by locking in existing resources when cheaper or cleaner alternatives have also been developed, and impeding state decarbonization programs. Many of these critiques have been discussed in news articles and FERC proceedings. Nonetheless, before considering when, if ever, buyer-side market power mitigation rules are justified, it is first worth describing the many ways MOPRs are undermining principles of competition in regions that have ostensibly restructured the electric power sector.

A. *Excess Capacity*

Extending MOPRs to resources that receive state subsidies will force customers to pay for capacity twice.²⁶¹ MOPRs are designed to procure a

any MOPR. In particular, it will cause excess capacity because it disregards some of the already existing capacity in the market.”)

256. See FERC, COMMISSIONER RICHARD GLICK DISSENT REGARDING FERC DIRECTING PJM TO EXPAND MINIMUM OFFER PRICE RULE, <https://www.ferc.gov/news-events/news/commissioner-richard-glick-dissent-regarding-ferc-directing-pjm-expand-minimum#>.

257. See Robert Walton, *New Jersey Looks To Exit PJM Capacity Market, Worried MOPR Will Impede 100% Carbon-Free Goals*, UTIL. DIVE (Mar. 31, 2020), <https://www.utilitydive.com/news/new-jersey-looks-to-exit-pjm-capacity-market-worried-the-mopr-will-impede/575160/>; SPG GLOB. MKT. INTELLIGENCE, FERC ASKED TO REVISIT MOPR ORDER; CONNECTICUT MAY DECIDE TO PULL OUT OF ISO-NE (Jan. 23, 2020), <https://www.spglobal.com/marketintelligence/en/news-insights/trending/k-hm4ghdtgdjafllnhbcbq2>.

258. ROB GRAMLICH & MICHAEL GOGGIN, TOO MUCH OF THE WRONG THING: THE NEED FOR CAPACITY MARKET REPLACEMENT OR REFORM, GRID STRATEGIES 10-11 (2019).

259. 163 F.E.R.C. ¶ 61,236, at P 150 (2018).

260. 162 F.E.R.C. ¶ 61,205, at P 21 (2018). The Commission’s skepticism of state subsidies stands in stark contrast to its recent endorsement of carbon pricing. Both state subsidies are designed to promote state policy preferences. But in the context of carbon pricing, FERC said that “it is the policy of this Commission to encourage efforts to incorporate a state-determined carbon price in RTO/ISO markets.” See *Carbon Pricing in Organized Wholesale Electricity Markets*, 173 F.E.R.C. ¶ 61,062, at P 7 (2020).

261. See, e.g., *ISO New England Inc. & New England Power Pool Participants Committee*, 158 F.E.R.C. ¶ 61,138 (2017) (Bay, Comm’r, concurring) (“Instead, the MOPR not only frustrates state policy initiatives, but also likely requires load to pay twice — once through the cost of enacting the state policy itself and then through the capacity market.”); *New York Public Service Commission v. New York Independent System Operator, Inc.*, 153 F.E.R.C. ¶ 61,022, at P 61 (2015) (discussing self-supply exemption to buyer-side mitigation rules as a means of “eliminat[ing] the risk of effectively requiring load serving entities to pay twice for capacity in the event that

predetermined amount of capacity that is expected to meet a region's expected demand.²⁶² Capacity markets therefore assume that no other resources will contribute to a region's reliability.

But when other resources enter the market, they provide capacity that supports resource adequacy. Today, resources that do not clear a capacity market auction—either because they were mitigated or for some other reason—will often enter the market anyway, and they will do so for one of two reasons. First, many eastern states have adopted renewable portfolio standards that require LSEs to procure a certain amount of carbon-free electricity.²⁶³ These requirements apply regardless of whether or not zero-carbon resources clear the capacity market auction. Thus, when MOPRs prevent carbon-free generators from clearing the market, they often do not prevent LSEs from purchasing electricity from resources that do not clear capacity auctions. Instead, they force LSEs to pay for the capacity needed to meet regional reliability in the capacity auction, and then again for additional capacity in order to comply with state renewable policies.²⁶⁴ The result is more capacity than is needed to meet the region's reliability goals.²⁶⁵

The second reason that capacity markets procure too much capacity is that they fail to adjust when resources experience price declines in the years between the capacity auction and the capacity commitment period.²⁶⁶ In the past decade, the average price of lithium-ion batteries has declined eighty-seven percent, from an average price of \$1,183 per kWh in 2010 to an average price of \$156 per kWh in 2019.²⁶⁷ Figure 1 shows this decline²⁶⁸:

a self-supplied resource does not clear the capacity market.”); *ISO New England Inc. and New England Power Pool Participants Committee*, 147 F.E.R.C. ¶ 61,173, at P 65 (2014) (discussing proposed renewable resource exemption from MOPR as a means to “reduce the double payment burden borne by customers who otherwise must pay both for renewable resources to satisfy state renewable resource obligations and for the same amount of capacity to satisfy the ICR, which could have been fulfilled in the first place by renewable resources”); *PJM Interconnection, L.L.C.*, 143 F.E.R.C. ¶ 61,090, at P 69 (discussing proposed self-supply exemption from MOPR as a means to avoid the problem of customers being “required to pay twice” for capacity).

262. See NORTH AM. ELEC. REL. CORP., *Methods To Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* at 3 (Mar. 2011), <https://www.nerc.com/files/ivgtf1-2.pdf>.

263. See NAT'L CONF. OF STATE LEGS., *State Renewable Portfolio Standards and Goals* (Apr. 17, 2020), <https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx>.

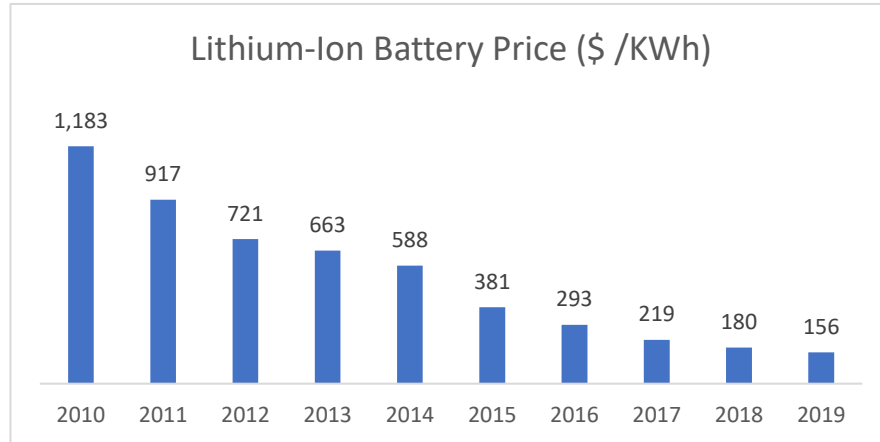
264. See GRAMLICH & GOGGIN, *supra* note 258, at 10-11.

265. *Id.* Municipal utilities and electric cooperatives have long voiced this complaint. See, e.g., Letter from the American Public Power Assoc. & the Nat'l Rural Electr. Coop. Assoc. to FERC (Mar. 5, 2018).

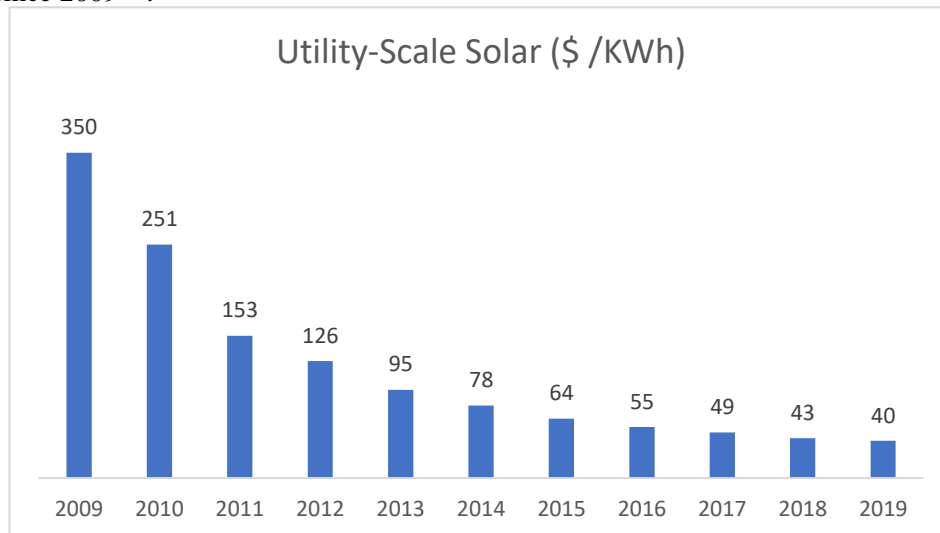
266. The three-year commitment period applies to PJM and ISO-NE, but not to NYISO, which runs its Capability Period Auctions much closer to the commitment period. See NYISO Manual 4, *Installed Capacity Manual* (June 2020), https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338 (“A Capability Period Auction will be conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity will be purchased and sold for the entire duration of the Capability Period.”).

267. See Rob Day, *Low-Cost Batteries Are About To Transform Multiple Industries*, FORBES (Dec. 3, 2019), <https://www.forbes.com/sites/robdays/2019/12/03/low-cost-batteries-are-about-to-transform-multiple-industries/#56ac26f01054>

268. See Logan Goldie-Scot, *A Behind the Scenes Take on Lithium-Ion Prices*, BLOOMBERG NEF (Mar. 5, 2019), <https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/>.



Solar prices have experienced a similar trend, declining eighty-nine percent over the past decade.²⁶⁹ Figure 2 shows the average price of utility-scale solar since 2009²⁷⁰:



When a resource expects its price to decline, the resource may be willing to enter a regional electricity market even if it does not receive revenue from the capacity market. If revenue from energy and ancillary services markets is sufficient for the resource to recover its costs, the resource will enter the market even if it does not receive a capacity payment.

These two phenomena—that state policies will cause resources to enter the market regardless of whether they clear the capacity market, and that some

269. See John Weaver, *Solar Price Declines Slowing, Energy Storage in the Money*, PV MAGAZINE (Nov. 8, 2019), <https://pv-magazine-usa.com/2019/11/08/sola-price-declines-slowing-energy-storage-in-the-money/#:~:text=Solar%20power's%20utility%20scale%20price,per%20year%20over%20the%20period>.

270. See LAZARD, 2019 LEVELIZED COST OF ENERGY (Nov. 2019), <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>.

resources can make a profit from energy and ancillary services markets alone—have contributed to the bloated reserve margins that have proven endemic in east coast electricity markets.²⁷¹ The three east coast grid operators have set a goal of procuring 13.5% reserve margins, yet NYISO, ISO-NE, and PJM each have reserve margins that hover around thirty percent.²⁷² In each of PJM’s capacity auctions, more resources have offered to sell capacity at the market clearing price than the grid operator determines is necessary for reliability.²⁷³ This is partly due to the fact that capacity markets procure the reserves needed in those regions without recognizing that capacity will enter the market regardless of whether or not it clears a capacity auction.²⁷⁴ Recall that FERC declared ISO-NE’s APR “unjust and unreasonable” for forcing consumers to pay for capacity twice.²⁷⁵ Yet MOPRs do just that.

B. Overcharge Consumers

MOPRs also force consumers to pay too much for capacity. This happens both because, as discussed above, MOPRs require consumers to pay for capacity they do not need, and also because MOPRs retain costly resources even after those resources are no longer needed to meet demand. Because capacity auctions in PJM and ISO-NE procure capacity three years before the capacity commitment period, they do not adjust to evolving market conditions.²⁷⁶ Consumers are forced to pay for resources that may have been able to provide the least expensive capacity three years ago, but which today could be replaced with cheaper alternatives.

One industry report found that the cost of procuring excess capacity could add up to \$45 billion over the next decade.²⁷⁷ Although the expected costs vary based on a variety of factors, the authors found that “[u]nder most scenarios, MOPR will result in billions or tens of billions of dollars in excess costs to electricity consumers across PJM.”²⁷⁸ The analysis estimated that, in the PJM region

271. A reserve margin is the amount of capacity in the region above the region’s expected peak demand. A 15% reserve margin means that the region can expect a 15% buffer when demand for electricity is highest. <https://www.eia.gov/todayinenergy/detail.php?id=39892#:~:text=The%20anticipated%20reserve%20margin%20considers,the%20summer's%20peak%20hourly%20load>.

272. These numbers describe summer reserve margins. See NAT’L ELECTR. RELIABILITY CORP., 2020 RELIABILITY ASSESSMENT (June 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf.

273. For example, in the August 2010 FCA, when the price floor of \$2.951/kW-month was reached, 5,374 MW of excess capacity, over 17%, remained in the auction. *ISO New England Inc.*, 133 F.E.R.C. ¶ 61,230, at P 4 (2010).

274. These are not the only reasons the regions have procured more supply than they need. Another reason is that the administratively determined demand curves are poorly designed. See Jacob Mays, *Quasi-Stochastic Electricity Markets* (Dec. 30, 2019), http://www.optimization-online.org/DB_FILE/2019/10/7414.pdf.

275. 135 F.E.R.C. ¶ 61,029, at P 9 (Apr. 13, 2011).

276. Adams James, *Explainer: How capacity markets work*, ENERGY NEWS NETWORK (June 17, 2013), <https://energynews.us/2013/06/17/explainer-how-capacity-markets-work/>.

277. See GRAMLICH & GOGGIN, *supra* note 258, at 28–29 (estimating the cost to consumers in PJM, NYISO, and ISO-NE if the MOPR is “fully imposed on resources that receive state incentives”).

278. See Catherine Morehouse, *PJM MOPR could cost market consumers up to \$2.5B annually, report finds*, UTIL. DIVE (May. 19, 2020), <https://www.utilitydive.com/news/pjm-mopr-could-cost-market-consumers-up-to-26b-annually-report-finds/578183/>. But see MONITORING ANALYTICS, POTENTIAL IMPACTS OF THE MOPR ORDER 2 (2020) (concluding that the expanded MOPR is “not expected to have an impact on the clearing prices and auction revenues in PJM’s 2022/2023 capacity auction”).

alone, these costs range from nearly \$10 billion²⁷⁹ to \$24 billion²⁸⁰ over the next nine years, depending on the default bid level that regulators select.

Two related problems are that MOPRs fail to reward marginal efficiencies, and that they do not permit resources to submit below-cost bids even when the supplier has a legitimate reason to do so. In ordinary markets, resources compete to reduce their own costs, secure favorable financing arrangements, hire cheap labor, and make accurate predictions about future market prices. A firm that does any of these things more efficiently than its rivals should be able to capture market share, reduce prices, and pass those savings onto consumers. But by design, MOPRs subject all resources to the same offer floor. As a result, capacity markets do not reward firms that offer superior services or prices than other generators in their same asset class.²⁸¹

And cost differences among generators of the same type can be significant. Some municipal electric cooperatives enjoy tax-exempt status, for example, and are therefore able to secure more favorable financing than private, investor-owned utilities.²⁸² These entities can often construct new generation less expensively than other firms, yet they are not permitted to reflect those savings in their capacity bids.²⁸³ Disputes about the appropriate offer floor for offshore wind is expected to prevent thousands of megawatts of offshore wind from clearing the ISO-NE and PJM capacity markets despite the fact that these generators would support the region's capacity needs and are expected to be built even if they do not clear the capacity auction.²⁸⁴

A related problem is that MOPRs do not allow firms to submit below-cost bids even when they have a legitimate reason to do so. Many resources are willing to sell a product at a loss, especially when they first enter a market, because they believe that their profits will increase alongside their market share. This can happen either because their product enjoys economies of scale, or because production costs will decline as their market share increases.²⁸⁵

MOPRs' failure to accommodate legitimate below-cost bidding strategies is especially harmful to emerging resources. In 2019, a storage facility sought to enter the NYISO market but was unable to do so because the market monitor found

279. ROB GRAMLICH & MICHAEL GOGGIN, *A MOVING TARGET: AN UPDATE ON THE CONSUMER IMPACTS OF FERC INTERFERENCE WITH STATE POLICIES IN THE PJM REGION*, GRID STRATEGIES 3 (2020) (based on the lower default bid level for existing nuclear resources included in PJM's March 2020 compliance filing).

280. *Id.* at 7–8 (based on the higher default bid level for existing nuclear resources in PJM's October 2018 filing).

281. Because firms can compete on these dimensions in energy markets, east coast electricity still leaves some room for competition among generators of the same type.

282. *See* Statement of Patrick E. McCullar on Behalf of the Delaware Municipal Electric Corporation and the American Public Power Association, Nos. ER11-2875-001-022, No. EL11-20-001, at 3 (2011).

283. *See id.*

284. *See* Heather Richards & Arianna Skibell, *FERC Order Could Bar Offshore Wind from U.S. Power Market*, E&E NEWS (May 13, 2020), <https://www.eenews.net/stories/1063120381>.

285. *See, e.g.*, Keith Head, *Infant Industry Protection in the Steel Rail Industry*, 37 J. INT'L ECON. 141, 141–45 (1994) (describing effect of the steel rail duty on the domestic steel rail industry). State governments may do so as well. New York, for example, has provided significant grants and tax credits to spur semiconductor manufacturing in the state. *See*, COMMITTEE ON COMPETING IN THE 21ST CENTURY: BEST PRACTICES IN STATE AND REGIONAL INNOVATION INITIATIVES, NAT'L RES. COUNCIL OF THE NAT'L ACAD. 156–61 (Charles W. Wessner, ed., 2013).

that the resource's net CONE was above the market clearing price.²⁸⁶ The resource appealed the market monitor's decision, challenging both the market monitor's calculations, and also arguing that it should be given some discretion to submit below-cost bids because it expected its costs to decline as it gained experience producing lithium-ion batteries.²⁸⁷ Both the market monitor and FERC disagreed, stating that a generic estimate of the unit's costs that was based on publicly available data—not the resource-specific data provided by the generator—disproved the firm's argument and established that the resource should not enter the PJM market.²⁸⁸ In another example, discussed in the next Part, FERC found that a NYPA resource should be subject to the MOPR because its *actual* capital costs were lower than the hypothetical, non-subsidized borrowing costs that formed the basis of CONE calculations in the region.²⁸⁹

C. *Favors Incumbents*

MOPRs require that east coast grid operators set one price floor for new resources and another for incumbents. In PJM, for example, resources that have previously cleared the capacity auction are subject to a low price floor (known as the “avoidable cost rate,” or ACR), and resources that offer to sell capacity at that price are likely to clear.²⁹⁰ Resources that seek to enter the market, by contrast, cannot bid below their net CONE.²⁹¹ In theory, both the ACR and net CONE are designed to measure the revenue a resource needs to earn from a capacity market in order to cover its costs.²⁹² Yet the ACR is calculated based on the lowest threshold necessary to remain in the market and counts only operating costs—not capital costs or maintenance expenses.²⁹³ Net CONE, by contrast, includes operating costs, capital costs, maintenance costs, and fixed costs.²⁹⁴ It is understandable that ACR excludes fixed costs. After all, incumbents have already completed construction.²⁹⁵ But there is no reason to include capital and maintenance costs, which apply equally to new and existing resources, in one calculation and not the other.

286. See *ISO New England Inc.*, 170 F.E.R.C. ¶ 61,132 (2020).

287. *Id.* at PP 31-34.

288. *Id.* at PP 44-45, 53.

289. See *Astoria Generating Company L.P. v. New York Independent System Operator, Inc.*, 140 F.E.R.C. ¶ 61,189 (2012). Also concerning, is that FERC delayed issuing the rehearing of its ruling for three years before reversing course.

290. See *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 F.E.R.C. ¶ 61,239, at P 138 (2019). The ACR reflects the annual operating expenses of those resources. See Joseph Browning & Ray Pasteris, *RPM Avoidable Cost Rate Development*, MONITORING ANALYTICS, (Nov. 8, 2006), <http://www.monitoringanalytics.com/reports/Presentations/2006/20061108-rpm-workshop-avoidable-cost-rate-dev.pdf>.

291. 169 F.E.R.C. ¶ 61,239, at P 138 (2019).

292. See Adam Keech, *Capacity Market Minimum Offer Price Rule Order*, PJM (Jan. 8, 2020), <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200108/20200108-item-04a-ferc-order-on-mopr.ashx>.

293. *Id.* at 7.

294. THE BRATTLE GRP., *PJM COST OF NEW ENTRY: COMBUSTION TURBINES AND COMBINED-CYCLE PLANTS WITH JUNE 1, 2022 ONLINE DATE 1* (2018), <https://www.pjm.com/-/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx>.

295. *Id.* Even that argument is speculative, as resource depreciation schedules generally extend beyond the first capacity commitment period.

Nor does it make sense to defer to the “lower threshold” of expected costs when assessing incumbent bids while applying a more exacting standard to new offers.

This unequal treatment creates “a noncompetitive bias in favor of existing resources and against new resources of all types, including new renewables and new gas fired combined cycles.”²⁹⁶ It also means that existing resources are likely to remain in the market even if it is more expensive to operate those resources than it is to replace them.

D. Increase Seller Market Power

MOPRs also entrench *supplier* market power.²⁹⁷ Electricity markets are already characterized by a high degree of seller concentration, and market monitors have routinely found that supplier market power is endemic in wholesale markets.²⁹⁸ Even though RTOs and market monitors have adopted a number of rules to ensure the competitiveness of market outcomes,²⁹⁹ capacity markets have remained vulnerable to the exercise of market power.³⁰⁰

MOPRs exacerbate seller market power both (1) by reducing the number of resources that submit competitive bids, and (2) by changing the opportunity cost of withholding capacity. New entry increases competition. Because MOPRs create barriers to new entry, they hamstring investment that would weaken incumbent suppliers’ market power.³⁰¹ That, in turn, contributes to ongoing concentration of supplier market power.³⁰²

In addition, by increasing the price of capacity, MOPRs create a windfall for generators that are able to extract monopoly rents by withholding supply. By artificially increasing the price of capacity, FERC has increased the money available to suppliers that exercise market power. The existence of the MOPR means that suppliers can increase their bids “secure in the knowledge that they will still out-

296. 169 F.E.R.C. ¶ 61,239, at P 49 (quoting Reply Brief of the Internal Market Monitor for PJM, Nos. EL16-49-000, ER18-1314-000, -001, EL18-178-000 (Nov. 6, 2018) at 4).

297. See *2011 Quarterly State of the Market Report for PJM: January through March*, MONITORING ANALYTICS 134, <https://www.monitoringanalytics.com> (finding “serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity”).

298. See *id.*

299. See *PJM Interconnection, L.L.C.*, 154 F.E.R.C. ¶ 61,151, at PP 3–5 (describing PJM’s seller-side market power mitigation rules).

300. See Reply Comments of the Inst. for Policy Integrity at N.Y Univ. Sch. of Law, *Calpine Corporation v. PJM Interconnection, LLC*, Docket Nos. EL16-49-000, EL18-178-000 at 14 [hereinafter Institute for Policy Integrity Comments]. MONITORING ANALYTICS, 2018 STATE OF THE MARKET REPORT FOR PJM 251 (2019). In PJM, for example, the Market Monitoring Unit found that the outcome of the 2021/2022 RPM Base Residual Auction “was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.” *Calpine Corporation v. PJM Interconnection, L.L.C.*, *supra* note 6, at P 56.

301. Institute for Policy Integrity Comments, *supra* note 300, at 15. According to the Institute for Policy Integrity, such price decreases would only counteract, not completely nullify, increases caused by supplier-side market power.

302. *Id.*

bid the mitigated offers.”³⁰³ If sellers are artificially inflating the price of capacity, then the entry of additional suppliers would drive down electricity prices counteract the price increases caused by supplier-side market power.³⁰⁴ Eliminating the MOPR would therefore reduce sellers’ incentives to manipulate capacity markets and mitigate the harms associated with seller market power abuse.³⁰⁵

E. Thwart Decarbonization Policies

MOPRs harm renewables for three reasons. First, resources that seek to enter the market are generally less carbon-intensive than resources that already participate in electricity markets.³⁰⁶ In providing a windfall to incumbents, MOPRs give carbon emitting resources a competitive advantage that is unavailable to the resources that seek to displace them.

Second, MOPRs prevent clean electricity providers from receiving revenues from capacity markets. Eleven of the fourteen states that participate in PJM have passed renewable portfolios standards.³⁰⁷ New York, the only state that participates in NYISO, recently passed one of the country’s most ambitious clean energy laws.³⁰⁸ All six states that participate in ISO-NE have passed renewable energy standards.³⁰⁹ As discussed in Part I, today capacity markets account for around thirty percent of generator revenues in PJM, ISO-NE, and NYISO.³¹⁰ MOPRs often exclude state-subsidized resources from capacity markets. In this way, MOPRs counteract, at least to some extent, the revenues clean sources of electricity receive as subsidies for their low-carbon attributes.

303. FERC, COMMISSIONER RICHARD GLICK DISSENT REGARDING FERC DIRECTING PJM TO EXPAND MINIMUM OFFER PRICE RULE, <https://www.ferc.gov/news-events/news/commissioner-richard-glick-dissent-regarding-ferc-directing-pjm-expand-minimum#>.

304. Institute for Policy Integrity Comments, *supra note* 300, at 15. According to the Institute for Policy Integrity, such price decreases would only counteract, not completely nullify, increases caused by supplier-side market power.

305. *Id.*

306. Today, the least cost resources are gas, solar, and wind. The entry of these resources tends to support decarbonization efforts because they displace coal and relatively higher-carbon emitting gas plants. This is not always the case, however, as some storage resources support coal-fired power plants by allowing coal to generate electricity at night, when prices are low, but sell it during the day, when wholesale prices rise. See Sonia Agarwal, et al., *Wholesale Electricity Market Design for Rapid Decarbonization*, ENERGY INNOVATION POLICY & TECH. LLC (June 2019).

307. Emma Nix, *State Energy Policy Scan*, PJM (July 26, 2019), <https://www.pjm.com/-/media/committees-groups/task-forces/cpstf/20190726/20190726-item-06a-energy-and-environmental-policy.ashx>.

308. See NYSERDA, NEW YORK STATE ANNOUNCES PASSAGE OF ACCELERATED RENEWABLE ENERGY GROWTH AND COMMUNITY BENEFIT ACT AS PART OF 2020-2021, <https://www.nyserdanyc.gov/About/Newsroom/2020-Announcements/2020-04-03-NEW-York-State-Announces-Passage-Of-Accelerated-Renewable-Energy-Growth-And-Community-Benefit-Act-As-Part-Of-2020-2021-Enacted-State-Budget>. FERC recently also rejected as unduly discriminatory NYISO’s attempt to accommodate New York’s clean energy goals by evaluating Public Policy Resources (energy storage, solar, wind, or other zero-emitting resources) ahead of non-Public Policy Resources when conducting the “Part A” mitigation exemption test. See 172 F.E.R.C. ¶ 61,206 at PP 8, 29 (Sept. 4, 2020).

309. ISO NEW ENGLAND, RESOURCE MIX (Jan. 20, 2020), <https://www.iso-ne.com/about/key-stats/resource-mix/>.

310. MONITORING ANALYTICS, 2019 PJM STATE OF THE MARKET REPORT 16 (2019), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume1.pdf; ISO NEW ENGLAND, 2019 ANNUAL MARKETS REPORT 4 (2019), <https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf>.

Third, MOPRs give resources that clear the *capacity* market an advantage in *energy* markets. Generators must receive enough revenue to cover their costs. A generator that receives a large capacity payment need not receive as much revenue from energy markets. Granted, generators will not offer to sell electricity in energy markets at a price that is lower than its marginal costs, because doing so would commit it to operating even when it would lose money doing so. But absent significant capacity market payments, generators that operate on the margin may not be able to remain in the market because the profits they receive from energy markets are insufficient to cover their fixed and capital costs. In increasing capacity revenues for fossil fuel generators, capacity markets retain resources that would otherwise retire and likely be replaced by cleaner resources.

F. Administrative Pricing All Over Again

It should by now be clear that MOPRs recreate many of the inefficiencies that are associated with administrative pricing. In restructured electricity markets, investors, at least in theory, receive a return on their investment only if they offer lower-cost services than their competitors. This creates an incentive to reduce costs and develop superior products. But by selecting which resources enter and exit the market, MOPRs resemble the system of utility rate regulation—and its accompanying inefficiencies—despite the fact that this system was supposed to have been rejected when policymakers restructured electricity markets in the 1990s and 2000s. The irony, of course, is that in attempting to promote an ideally competitive market free from outside payments, FERC has imposed an intrusive form of administrative pricing.³¹¹

And there is one other way that MOPRs recreate the inefficiencies that are generally associated with cost-of-service rate regulation. Cost-of-service rate regulation is circular. The value of an asset depends on the firm's expected future cash flows, yet expected future cash flows are based on a regulator's assessment of the asset's value.³¹² MOPRs recreate this circularity in some respects. Regulators calculate price floors by looking at the cost of capital, labor, and land. These price floors determine which resources can sell capacity at their preferred price. The administratively-set demand curve, in turn, determines how much revenue generators earn from capacity markets. A generator's cost of capital, however, will depend in large part on a generator's expected revenue. The result is that at least one of the inputs that goes into calculating net CONE is itself partly determined by the administrative decision about how to calculate net CONE for that resource.

311. This is especially ironic in light of a recent PURPA rule, Order No. 872, where FERC endorsed a competitive bidding process to discover avoided capacity costs precisely because it found that administratively-determined avoided cost rates could result in utilities being required to purchase more capacity than necessary. See 172 F.E.R.C. ¶ 61,041, at PP 411, 416, 420–24 (2020).

312. See, e.g., *Missouri ex rel. Southwestern Bell Tel. Co. v. Public Serv. Comm'n*, 262 U.S. 276, 292 (1929) (Brandeis, J., concurring); *Helmsley v. Borough of Fort Lee*, 78 N.J. 200, 213–14, 394 A.2d 65, 71 (1978).

V. RESOURCE-SPECIFIC EXEMPTIONS

FERC has at times acknowledged that price mitigation rules resemble administrative pricing,³¹³ and it has countered that MOPRs do not disfavor new entry because the existence of the resource-specific exemption allows resources to avoid mitigation where their costs are below CONE. The purpose of the resource-specific review, according to FERC, is to “operate[] as a safety valve that helps to avoid over-mitigation of resources that demonstrate that their offers are economic based on a rational estimate of their expected costs and revenues without reliance on out-of-market financial support through State Subsidies.”³¹⁴ The Commission has explained that “[t]rigger prices form a screen: offers at or above the trigger price are accepted into the FCA with no further review; offers below the trigger price may nevertheless be accepted into the FCA if they are justified with the IMM during the unit-specific review process.”³¹⁵ Thus, FERC has argued that MOPRs do not unfairly discriminate against new resources because generators can use the resource specific exemption to determine their own costs.

But the resource-specific review process does not appear to allow resources to enter capacity markets on their own terms. Only a small amount of capacity that has entered capacity markets has taken advantage of the resource-specific exemptions. Despite FERC’s insistence that resource-specific exemptions permit resources to compete on a level playing field, the resource specific exemption does not offer a viable alternative to mitigation even for resources that can submit competitive bids.

A. *The Unit-Specific Exemption*

In PJM, a resource seeking to qualify for the resource-specific exemption must submit a request to do so, along with “documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues.”³¹⁶ The Market Monitoring Unit (MMU) determines whether the offer is acceptable.³¹⁷ PJM then performs its own review, and may calculate an acceptable offer based on the data and documentation provided by the resource.³¹⁸ Finally, the seller must notify both the MMU and PJM of the minimum offer to which it agrees at least sixty days before the auction opens.³¹⁹

ISO-NE has developed a similar process. The market monitor reviews offers that are below the Offer Review Trigger Price for that asset class.³²⁰ Resources can submit documentation that, in theory, should allow the Internal Market

313. *Id.*

314. 169 F.E.R.C. ¶ 61,239, at P 16. *See also* 135 F.E.R.C. ¶ 61,022, at P 102 (“In response to those who argue that the impact screen should be retained as a check on “over-mitigation,” we note that, as discussed later, a new resource whose actual competitive costs are below the offer floor will not be mitigated, as such a resource can verify its actual competitive costs with the IMM.”).

315. 142 F.E.R.C. ¶ 61,107, at P 38 (2011).

316. PJM OATT Attachment DD § 5.14(h)(5)(i)-(ii).

317. *Id.* at § 5.14(h)(5)(iv). The MMU must do this at least 90 days prior to the offer period for the auction. *See id.*

318. *Id.*

319. *Id.*

320. ISO-NE, Market Rule 1, § III.A.21.2

Monitor to determine whether an offer is consistent with the resource's costs. This calculation excludes out-of-market revenues.³²¹ If the Internal Market Monitor determines that the requested offer price is consistent with its own estimate, the resource may submit a bid at the requested price.³²² The Internal Market Monitor may also calculate its own New Resource Offer Floor Price that differs both from the ORTP and the resource's requested price.³²³

NYISO takes a different approach. It compares unit-specific net CONE to the three-year ICAP forecast to determine whether a unit is exempt from mitigation under its "Part B" mitigation exemption test.³²⁴ If the unit-specific net CONE is lower than the three-year ICAP forecast, the unit is exempt from mitigation.³²⁵

B. The Unit-Specific Exemption Has Been Used Rarely

One reason to be skeptical about the unit-specific resource exemption is that only a small amount of capacity has entered the PJM and ISO-NE capacity auctions through these processes.³²⁶ In the 2021/2022 auction, which took place in 2018, PJM granted 4,344.0 MW of the 7,276 ICAP MW of unit-specific exception requests,³²⁷ which is just over 2% of the 192,449.2 capacity that the market monitor found eligible to participate in the auction. In the 2020/2021 BRA, which took place in 2017, no resource requested a unit-specific exception.³²⁸ In the five most recent ISO-NE capacity auctions, the Internal Market Monitor reviewed 460 new supply offers totaling approximately 16,400 MW of qualified capacity.³²⁹ The Internal Market Monitor mitigated approximately 56% of the offers it reviewed, or about 64% of new capacity, resulting in an average increase in offer price of \$3.23/kW-month.³³⁰ For reference, that increase amounts to an additional \$3,876,000 per year for a relatively small, 100 MW generator.³³¹ As in PJM, unit-specific exception requests represent a small portion of total capacity: the 16,400 MW that asked for a different price floor is less than one percent of the 200,000 MW that qualified to participate in the auctions.³³²

321. *Id.* § III.A.21(b).

322. *Id.* § III.A.21(b)(v).

323. *Id.* § III.A.21(b)(vi).

324. *See* NYISO, Services Tariff, § 23.4.5.7.2.

325. *Id.*

326. This fact is not dispositive. It could also indicate that the net CONE calculation is highly precise, and that resources do not take advantage of the unit-specific resource exemption because the net CONE reflects their actual costs. The next subpart suggests this alternative explanation is unconvincing.

327. MONITORING ANALYTICS, 2019 PJM STATE OF THE MARKET REPORT 280, 282 (2019). Monitoring Analytics' report does not state whether the requests granted resulted in offers at the price originally requested by the resource or whether the offers were mitigated upward.

328. *Id.*

329. ISO-NE, 2019 ANNUAL MARKETS REPORT 184. Over 1 million MW of capacity cleared the five most recent capacity auctions. *Id.* at 13.

330. *Id.* at 185. The price increased from an average submitted price of \$2.90/kW-month to the IMM-determined price of \$6.13/kW-month. *Id.* Some mitigated resources were also able to elect the then-existing Renewable Technology Resource exemption from ISO-NE's MOPR. *Id.*

331. $(\$3.23 * 100,000 * 12)$. One MW is 1,000 KW.

332. *See* ISO-NE, FORWARD CAPACITY AUCTION TOTALS FLOW DIAGRAM, <https://www.iso-ne.com/static-assets/documents/2018/05/fca-flow-diagram.pdf>.

C. *The Unit-Specific Exemption Has Entrenched Administrative Pricing*

The resource-specific exception bears many of the hallmarks of administrative pricing. Publicly available data about the application process, though rare, indicates that the price floor that applies to resources that attempt to use the exemption ultimately reflects the market monitor's assessment of the resource's costs and not the resource's assessment of its own costs.

1. DEMEC

Take, for example, Delaware Municipal Electric Corporation's (DEMEC), which attempted to enter the PJM 2014 base residual auction. PJM's MOPR required DEMEC to submit evidence showing why it should be allowed to offer to sell capacity at less than ninety percent net CONE.³³³ PJM calculated that the CONE for this type of resource was \$247.52/MW-day. DEMEC's analysis showed that its costs were only "a small fraction" of that figure (approximately forty percent net CONE).³³⁴

The IMM disagreed. It said that it was "opposed to almost every point" in DEMEC's initial calculation of its cost.³³⁵ In particular, the IMM challenged DEMEC's assessment of its financing costs. The IMM "felt that DEMEC's access to tax-exempt financing as a not-for-profit public power system constituted a "subsidy," even though this subsidy reflected DEMEC's "actual cost of financing."³³⁶ As a result, the IMM increased DEMEC's financing rate by 2%.³³⁷ Because DEMEC felt that this upward adjustment would prevent it from clearing the auction, it appealed the IMM's decision to FERC.³³⁸ Ultimately, the IMM and DEMEC settled on an offer floor that was "substantially higher" than that initially proposed by DEMEC.³³⁹

The unit-specific review process thus resulted not in an offer floor that reflected DEMEC's assessment of its own costs, but rather an administrative compromise that landed somewhere between DEMEC's cost-based calculation and the market monitor's own estimate.³⁴⁰

2. Able Grid

This problem is not limited to PJM. In 2019, a company called Able Grid sought to use lithium-ion batteries to support grid reliability in New England. Able Grid found itself caught in a battle between ISO-NE's two market monitors (ISO-

333. Statement of Patrick E. McCullar on Behalf of the Delaware Municipal Electric Corporation and the American Public Power Association, Docket Nos. ER11-2875-001, -022, No. EL11-20-001, at 3 (2011) [hereinafter McCullar Statement].

334. *Id.*

335. *Id.*

336. *Id.*

337. *Id.*

338. McCullar Statement, *supra* note 333.

339. *Id.*

340. This process resembles a phenomenon Anthony Casey and Julia Simon-Kerr identified as occurring when judges value assets. Casey and Simon Kerr find that, rather than rely on accurate valuation methods, judges often "eschew expertise and valuations grounded in research and mathematical models in favor of the middle ground." Anthony J. Casey & Julia Simon-Kerr, *A Simple Theory of Complex Valuation*, 113 MICH. L. REV. 1176, 1177 (2016).

NE has both an “internal” and an “external” market monitor). In its informational filing for the 2023-2024 Capacity Commitment Period, ISO-NE included details about which resources would be allowed to participate in the capacity auction and which would not.³⁴¹ The External Market Monitor claimed that the Internal Market Monitor over-mitigated energy storage resources, and that it did so because it relied on unreasonably low estimates of the revenue those resources would earn in energy and ancillary services.³⁴² The External Market Monitor asked FERC to direct the Internal Market Monitor to re-estimate the net revenues, and to use the External Market Monitor’s methodology.³⁴³ Able Grid, which had proposed two battery storage projects that were rejected under the Internal Market Monitor’s methodology, intervened, claiming that although it had provided documentation to support its proposed offer floor prices, the IMM denied its submissions and instead substituted a different offer floor.³⁴⁴ Like the External Market Monitor, Able Grid argued that the IMM relied on unreasonably low estimates about future energy market revenues.³⁴⁵

Able Grid also claimed that it had provided documentation that countered the IMM’s analysis of its fixed and capital costs.³⁴⁶ But according to the IMM, Able Grid’s evidence was irrelevant, because the IMM instead relied on publicly available data that analyzed projects on a generic basis.³⁴⁷ Able Grid also stated that the IMM relied on a FERC-approved cost of new entry study to calculate Able Grid’s cost of capital, rather than the calculations that Able Grid provided.³⁴⁸ In other words, disagreement about future energy and ancillary services revenues, and about whether it is more appropriate to use information that a generator submits about the costs of its project or generic estimates about the costs of constructing generators of that type, was the reason Able Grid was unable to offer to sell capacity at the price it felt was justified.

As with DEMEC, FERC rejected Able Grid’s argument, agreeing with the IMM that Able Grid had not provided sufficient support for its estimates of total investment costs, salvage value, and capital costs. FERC also found that the IMM’s estimate of net revenues was reasonable.³⁴⁹ In particular, the Commission said that it was reasonable for the IMM to rely on a generic estimate of net revenues and other publicly available data, rather than resource-specific estimates.³⁵⁰

341. 170 F.E.R.C. ¶ 61,132, at PP 1-10 (2020).

342. *Id.* at PP 19–24.

343. *Id.* at P 24.

344. *Id.* at P 27.

345. *Id.* at P 34.

346. 170 F.E.R.C. ¶ 61,132, at P 29.

347. *Id.* at P 31. Further, Able Grid argued that the IMM used an overly conservative measure of salvage value.

348. *Id.* at P 33. The IMM argued that it was justified in rejecting Able Grid’s requested offer floor prices because the values of those prices were driven by unreasonably high estimates of net energy and ancillary services revenue. *Id.* at P 44.

349. *Id.* at PP 51, 53.

350. *Id.*

3. Astoria Energy II

Astoria Energy provides perhaps the most dramatic example of the extent to which the unit specific exemption is another form of administrative pricing. Astoria owned a 575 MW generating facility. In July 2011, NYISO permitted Astoria to offer into the July 2011 capacity auction without being subject to the offer floor.³⁵¹ At the time, a resource would not be subject to mitigation if the average capacity market prices across six capability periods was projected to be higher than the resource's net CONE.³⁵² In making the exemption determination, NYISO used Astoria II's actual cost of capital, which was based on favorable financing terms that resulted from a twenty-year power purchase agreement with the New York Power Authority (NYPA) and NYPA's good credit rating as a state-chartered entity.³⁵³

Two generators challenged this determination.³⁵⁴ The complainants argued that the financing terms available to Astoria as the result of the power purchase agreement "were not the result of legitimate competitive advantage but rather are attributable to out-of-market payments."³⁵⁵ They further alleged that the power purchase agreement was the result of discriminatory contracting process because it was limited only to new resources.³⁵⁶ The generators felt that NYISO should have instead used the cost of capital figures for a proxy unit.³⁵⁷

FERC agreed.³⁵⁸ It found that the use of actual cost of capital was inappropriate because the power purchase agreement was an out-of-market payment available only to Astoria II that allowed it to attract capital on more favorable terms "inconsistent with a competitive offer."³⁵⁹ FERC also found that the power purchase agreement was discriminatory despite the fact that the request for proposals that culminated with the power purchase agreement had been open and transparent.³⁶⁰ Citing a previous MOPR order, FERC determined that the financing costs associated with the power purchase agreement constituted an "irregular or anomalous" cost advantage "not in the ordinary course of business."³⁶¹ Accordingly, FERC required NYISO to ignore Astoria II's actual costs in favor of a proxy reference unit's costs.³⁶²

351. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,189, at P 37 (2012).

352. *Id.* at PP 3–6.

353. *Id.* at PP 126–27.

354. *Id.* at P 11.

355. *Id.* at P 123.

356. 140 F.E.R.C. ¶ 61,189, at P 123.

357. *Id.* at P 124.

358. *Id.* at P 134.

359. *Id.* at P 135.

360. *Id.*

361. 140 F.E.R.C. ¶ 61,189, at P 135 (citing *PJM Power Providers Grp. v. PJM Interconnection, L.L.C.*, 137 F.E.R.C. ¶ 61,145, at P 245 (2011)).

362. *Id.* FERC ultimately reversed course in 2015 after a lengthy administrative process, finding that the agreement was not discriminatory and thus that Astoria could be exempted based on its own cost of capital. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 151 F.E.R.C. ¶ 61,044 (2015). Even so, FERC suggested that ISOs should be on the look-out for circumstances that would merit replacing actual costs with proxy costs.

No one disputed that Astoria's actual costs fell below CONE, but FERC still denied, at least initially, Astoria's exemption request.³⁶³ The unit-specific exemption thus as a practical matter seems to involve a great deal of administrative oversight and, even generating units whose costs are below the CONE have often failed to qualify for the exemption. The unit-specific exemption therefore does present a meaningful alternative to the MOPR, but rather another layer of administrative pricing for resources seeking to enter capacity markets at a price below the MOPR offer floors.

VI. WHEN, IF EVER, ARE MOPRS JUSTIFIED

Given the problems MOPRs generate, it is worth considering if price mitigation is ever justified. As Part I showed, FERC has insisted that MOPRs are needed to prevent price suppression. The central question this Article takes up is when price suppression harms wholesale electricity markets. This Part explains that price suppression is problematic when it is a means of exercising market power. Below-cost bids submitted by net buyers can create a market for lemons in which independent power producers are driven out of business. Price suppression is not problematic, however, when it is a consequence of state subsidies or of competitive bidding strategies.

A. *State Subsidies Do Not Undermine Capacity Markets*

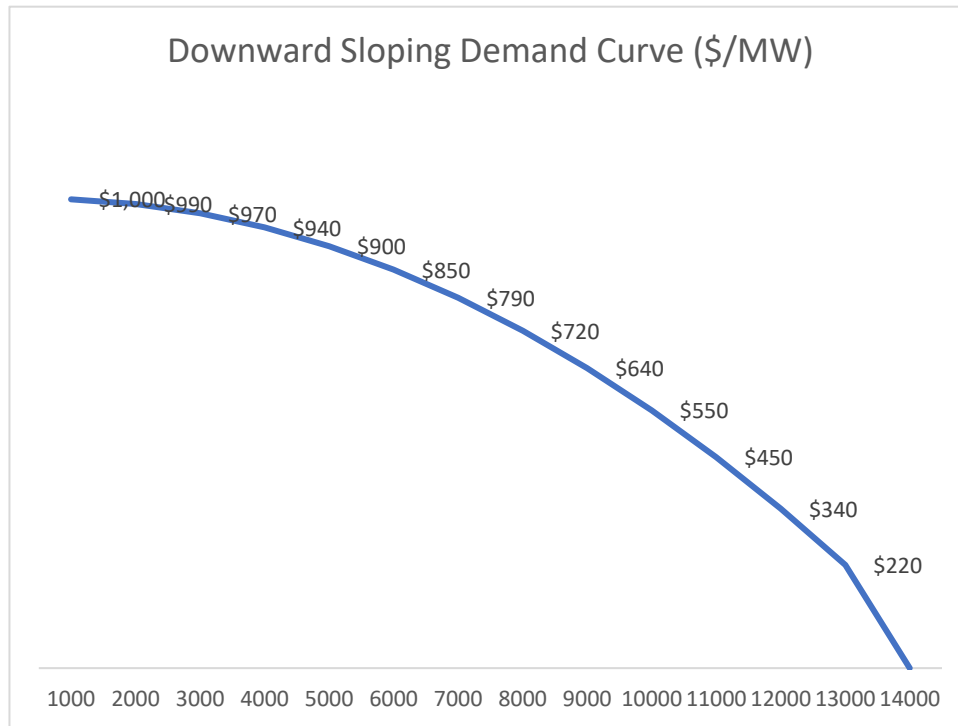
By itself, price suppression poses no harm to wholesale electricity markets. Grid operators aim to procure an amount of capacity that will maintain resource adequacy in their regions. The way they do this in the east coast electricity markets is to construct a downward sloping demand curve that provides for descending prices and corresponding increases in quantity supplied. This demand curve is an administrative construct and does not necessarily correspond to consumers' willingness to pay or an actual demand curve, though it is intended to approximate consumers' willingness to pay for various quantities of capacity.³⁶⁴ The downward sloping demand curve is designed to estimate the demand for capacity resources over a range of different prices.³⁶⁵ Figure 3 models a downward-sloping demand curve for capacity³⁶⁶:

363. *Id.* at P 78.

364. It is also worth mentioning that capacity market rules themselves favor certain resources and thus fail to create the type of level playing field that FERC claims to be protecting when it mitigates generator bids. See Jacob Mays, David Morton, & Richard O'Neill, *Asymmetric Risk and Fuel Neutrality in Capacity Markets*, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3330932.

365. See ISO-NE, *Downward Sloping Demand Curve*, <https://www.iso-ne.com/committees/key-projects/implemented/fcm-sloped-demand-curve>. Grid operators today do not agree to procure a fixed amount of capacity regardless of price, though ISO-NE actually used a vertical demand curve from 2006 to 2010.

366. The grid operators' actual demand curves are slightly more complicated than the stylized example above. See ISO-NE, *Regulatory Tariff*, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf; PJM, *VRR Curve*, <https://www.pjm.com/-/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-variable-resource-requirement-curve-study.ashx>.



The downward sloping demand curve will result in more capacity entering the market when price decreases and less capacity when price increases. In the example above, if the price of capacity is \$1,000 per MW, it will procure only 1000 MW of capacity. If the price of capacity is \$220 per MW, it will procure 13,000 MW.

Thus, rather than lead to reliability problems, state subsidies actually support resource adequacy. State subsidies allow resources to rely on non-wholesale market revenues to cover some of their costs. They therefore drive the price of capacity down. In doing so, they shift the supply curve to the right, which causes supply to intersect demand at a lower price point. Imagine if, in the Figure above, the supply curve would intersect with the demand curve at \$850 when the grid operator mitigates state-subsidized bids and \$790 when it allows state-subsidized resources to participate in the auction. With mitigation, the capacity auction would procure 6,000 MW of capacity. Without mitigation, it would procure 7,000 MW of capacity. In other words, the use of a downward-sloping demand curve means that state subsidies will result in more capacity clearing the market and at a lower price.³⁶⁷

367. One might argue that a problem with state subsidies is that they lead to too much supply, not too little, because they cause the supply curve to shift to the right and, in that way, procure more supply than is needed. One response to that is that the downward sloping demand curve reflects the value of capacity at different price points, and so the market should procure more capacity when price decreases. Moreover, even if this is problematic, MOPRs exacerbate—rather than mitigate—this issue by further bloating reserve margins. *See supra* Part II.C.

B. Buyer Market Power Can Harm Capacity Markets

Buyer market power, by contrast, can, at least in theory, harm wholesale electricity markets. But while FERC has asserted that buyer market power is a problem, it has never actually explained how market manipulation by net buyers distorts wholesale electricity markets. The problem with buyer market power in capacity markets is that it threatens to prevent independent power producers from entering the market. The issue is not simply that net buyers have an incentive to suppress capacity market prices. It is that they have an incentive to do so indefinitely. A net buyer will have an incentive to suppress capacity prices whenever competitors are in the market, because the firm may be able to raise prices and extract monopoly rents when its competitors exit the market. In fact, because even the threat of predation can deter market entry, net buyers will be less inclined to enter the market if they are concerned about predation.

Price suppression can benefit net buyers for two reasons. First, as explained in Part I, by suppressing wholesale market prices, net buyers can reduce the price they pay for capacity when competitors are in the market. Second, by capturing market share that would otherwise belong to independent power producers, net buyers can engage in predatory pricing. In setting prices below a competitive level, market manipulation could drive independent power producers to exit the market. And, if independent power producers know that they are competing against firms that have an incentive to suppress capacity market prices below competitive levels, they might fear that such market manipulation will continue to prevent capacity market prices from ever rising high enough to allow independent generators to cover their costs. This may drive independent firms to leave the market and deter prospective competitors from entering. The existence of an administratively-constructed demand curve will lead the region to continue to procure sufficient capacity, but only from net buyers that are able to benefit from extracting monopoly rents once their predatory pricing has driven their competitors out of the market.³⁶⁸

If buyers' anticompetitive conduct prevents independent power producers from entering the market, the only supply that will be left would be provided by firms that have agreed to sell capacity at a loss.³⁶⁹ Market manipulation could drive independent power producers—the firms whose profits come from sales of electricity and that bring competition to electricity markets—out of the market. Ultimately, this could harm net buyers if they are forced to sell capacity at a loss. While net buyers benefit from predation when the price suppression reduces the amount that they must pay for capacity, it is possible that they would be forced to sell capacity at a loss if they successfully drive out their competitors. Presumably, though, net buyers expect to benefit from predatory pricing by raising prices after driving out their competitors. If the threat of predatory pricing drives out competitors, utilities may be able to extract monopoly rents from selling electricity. Thus, the justification for mitigation is not that a policy or bidding strategy suppresses wholesale prices, but that it does so in a manner that prevents

368. This is a variant on the Market for Lemons. *See*, Akerlof, *supra* note 20, at 488.

369. It will be problematic for these firms if they are required to continue to sell capacity at a loss. It would benefit them if they are then able to raise prices.

resources from competing along price. If such behavior leads to vertical reintegration, it really would undermine competitive electricity markets.

There is at least some reason to be concerned that some net buyers of electricity are well-positioned to successfully predate. Ordinarily, courts are skeptical of predation claims.³⁷⁰ Successful predation is difficult to execute. It generally requires that firms with market power sell a product at a loss. The period of losses naturally deters predatory pricing, because firms are reluctant to incur certain losses for the uncertain possibility of a future monopoly, especially since there is a risk that rivals will reenter the market once the firm raises prices back to a profitable level. In addition, it is extremely difficult to distinguish predatory pricing from other benign motivations for price cuts. Recognizing that firms are reluctant to sell at a loss³⁷¹ and that over-enforcement would deter efficient price cuts,³⁷² courts have created a high bar for successful predation claims.

But this logic does not apply to net buyers of capacity. As explained in Part II, net buyers in electric power markets actually profit while engaging in predatory pricing. While their generators incur a loss, net buyers recover those losses by reducing the price they pay to purchase capacity. As a result, unlike net buyers in other markets, price cuts do not erode the buyers' profits while it is predating. There is therefore reason to think that net buyers might engage in price cuts not simply because they can drive rivals out of the market (the standard explanation of predation), but also because predatory pricing is profitable even when the firm is engaged in predatory pricing. In other words, because net buyers of electricity benefit from price suppression, they have a strong additional incentive to predate.³⁷³

This is the most generous interpretation of FERC's MOPR, however, and it is at best theoretical. FERC does not appear to have offered any evidence that net buyers are purposefully manipulating capacity prices. Nor has the Commission explained why ordinary enforcement actions would fail to deter this type of behavior more directly. As a result, while there may be some reason to worry that net buyers are abusing their market power, it is not at all clear that MOPRs are an appropriate remedy.

In any event, none of this logic applies to resources that receive state subsidies. Unlike capacity offered by net buyers, subsidized resources benefit financially when capacity prices increase. Unlike net buyers, state-subsidized resources have no incentive to submit below-cost bids to manipulate capacity markets. Generators that receive a state subsidy will, like all resources, bid

370. *Brooke Grp. Ltd. v. Brown & Williamson Tobacco Corp.*, 509 U.S. 209 (1993).

371. *Id.* (quoting *Matsushita Elec. Indus. Co. v. Zenith Radio Corp.*, 475 U.S. 574, 589 (1986) to the effect that "predatory pricing schemes are rarely tried, and even more rarely successful"). See also Aaron S. Edlin, *Stopping Above-Cost Predatory Pricing*, 111 *YALE L.J.* 941 (2002).

372. *Barry Wright Corp. v. ITT Grinnell Corp.*, 724 F.2d 227 (1983) ("The antitrust laws very rarely reject such beneficial 'birds in hand' for the sake of more speculative (future lowprice) 'birds in the bush.'") (Breyer, J.).

373. In fact, vertically integrated utilities that can recover some of their generation costs in state ratemaking proceedings may have an additional incentive to submit below-cost bids. See *Fuel Adjustment Clauses & Other Cost Trackers*, ELEC. CONSUMERS RES. COUNCIL, <https://Elcon.Org/Fuel-Adjustment-Clauses-cost-trackers/> ("A fuel adjustment clause (FAC) is a tariff provision which permits a change in rates to occur as a result of a change in the cost of fuel or a portion of purchased power expenses. These changes occur without the utility filing a formal rate case.").

whatever price allows them to recover their costs. When a state subsidizes a resource, it is presumably compensating the generator for providing something of societal value, such as carbon-free electricity, and the payment allows the subsidized resource to operate even if it receives less revenue from wholesale markets.

But such subsidies do not prevent the capacity market from working. The capacity market is an administrative construct. When capacity is needed, the price of capacity will increase. This is axiomatic. The market is designed such that the capacity price increases whenever there is a capacity shortfall. This price increase will induce market entry whenever there are not enough resources available to meet expected peak demand.

There is therefore no reason for independent power producers to be concerned that the participation of state-subsidized resources will lead to the collapse of competition in capacity markets. A state subsidy reduces the price of capacity, but subsidized resources remain sensitive to the price signals generated by the wholesale market in which they operate, and the price of capacity will still increase whenever there is a capacity shortfall. Thus, resources that provide the lowest-cost service needed by the grid will clear the capacity auction. While subsidies may make some resources less likely to clear, they do so only because a state has agreed to accept some of the resource's costs.³⁷⁴

To the extent that buyer market power is a problem in east coast electricity markets, policymakers should target the source of the problem. This likely involves stronger ex post enforcement of market power abuses. Perhaps, also, regulators should consider requiring large transmission utilities to divest themselves of their generation assets.³⁷⁵ Moreover, while contracts for differences do allow distribution companies to hedge against price volatility, so too do options and futures.³⁷⁶ Since other hedging strategies are available to LSEs, FERC could prohibit LSEs that are in a position to exercise market power from entering into the type of contract that has left capacity markets vulnerable to market power abuses.

The main point, though, is that whatever economies of scale follow from vertically integrating generation and transmission does not justify the degree of administrative pricing that now characterizes east coast electricity markets—especially when those interventions continue to be justified as necessary to preserve competition. To date, FERC has only identified two situations in which capacity markets are vulnerable to buyer market power abuses: when net buyers build their own capacity, and when states or net buyers enter a contract for differences that

374. The one exception is a contract-for-differences which, as discussed in Part I.B, allows the state to act as a buyer. When a state instructs a utility to procure a certain type of resource through a contract for differences, it forces other ratepayers in other states to bear as much of the cost of the subsidy as possible. By contrast, rather than offload costs onto other states and market participants, ordinary state subsidies increase the amount of capacity that enters a market.

375. Full divestiture, however, could only be accomplished either if Congress granted FERC additional authority, or if states intervened more aggressively than they have in the past. *See* Matthew Christiansen & Joshua Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360 (2021). As noted, our concern is with large distribution utilities that are in a position to exercise market power, not with small government utilities or rural co-ops.

376. The Intercontinental Exchange lists over a hundred futures and options products that would allow LSEs to hedge against price volatility in capacity markets. *See e.g.*, <https://www.theice.com/products/Futures-Options/Energy/Electricity>.

gives the generator an incentive to offer to sell capacity for \$0. Absent evidence that capacity markets are vulnerable to other types of buyer market power abuses, FERC should limit MOPRs to these two situations, and even then, the Commission should not impose administrative pricing until it has proof that such market power abuses are actually occurring—evidence that the Commission did not provide even when MOPRs ostensibly targeted market power abuses.

VII. CONCLUSION

For over a decade, FERC has used MOPRs to protect competitive electricity markets. It has justified these interventions by claiming that MOPRs enable perfectly competitive markets that match physical power flows to system needs. But as this Article has shown, the problem FERC diagnosed in the mid-2000s is a market power problem—not a price suppression problem. While FERC has lost sight of this original purpose, there does not appear to be any plausible reason to mitigate resources that do not exercise market power.

In expanding mitigation to resources that do not exercise market power, MOPRs have the opposite of their intended effect. They have led to a system of administrative pricing that has increased prices, contributed to bloated reserve margins, and hamstrung state de-carbonization efforts. FERC has also long claimed to be technology-neutral—that it breaks down barriers to entry and makes sure that resources are able to compete on a level playing field.³⁷⁷ Yet, MOPRs treat incumbent merchant generators more favorably than other suppliers.

In order to promote competitive electricity markets, FERC should adopt a lighter regulatory touch. Rather than dictate the terms of electricity market participation, it should intervene only when there is clear evidence of market manipulation or market power abuse. Even then, aggressive enforcement would be preferable to administrative pricing. A better approach to buyer market power would prohibit vertical integration between distribution and generation facilities. If regulators are unable to do this, either because of jurisdictional limitations or political will, they should only mitigate bids when the bidder has the incentive and ability to exercise monopsony power.

377. See e.g., *PJM Interconnection, L.L.C.*, 167 F.E.R.C. ¶ 61,058, at P 59 (2019) (endorsing “a technology-neutral approach ensures that no resource that can perform the same service is unnecessarily excluded from fast-start pricing treatment”).