

Note

The Resource Adequacy Requirement in FERC's Standard Market Design: Help for Competition or a Return to Command and Control?

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Although electricity markets' march toward competition has not been a complete success, the Federal Energy Regulatory Commission ("FERC") remains committed to easing wholesale electricity markets toward that goal. Indeed, FERC's Standard Market Design Notice of Proposed Rulemaking makes some headway: Locational marginal pricing, for example, will force load to internalize the congestion costs of its consumption and will signal the need for new transmission and generation. FERC, however, has embraced price caps in spot markets and, to make the markets work despite the price caps, has proposed a Resource Adequacy Requirement ("RAR") to ensure that adequate generation exists to deliver electricity to load. If RAR achieves FERC's objective, it will stunt the growth of demand response, a necessary component of stable competition. Further, RAR will permit the perpetuation of the current price-cap regime, which distorts price signals. The claim that RAR together with price caps are only temporary measures to help put wholesale markets on surer footing seems misguided; until price caps are raised significantly above present levels, load-serving entities and load itself lack the incentive to invest in technologies necessary to make demand response a reality. If this were not enough to counsel against promulgating the RAR, the proposal is internally contradictory and, according to the relevant statutes, lies outside FERC's jurisdiction to implement or enforce. FERC should discard the RAR and current price caps and instead adopt a reformist program that will better allow scarcity spot prices to ensure generation adequacy.

Introduction	433
I. The Rationale Behind the Resource Adequacy Requirement	436
A. <i>The Unique Properties of Electricity and Their Implications for Electricity Markets</i>	436
1. Price Caps and Market Mitigation	437
2. Insufficiency of Price-Spike Signals	440

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3. Relation to Capacity Requirements.....	441
B. <i>ICAP's Inadequacies</i>	442
C. <i>FERC's Alternative: A Resource Adequacy Requirement</i>	443
II. Implementation Difficulties.....	444
A. <i>Substantive Problems</i>	444
1. Tension with Competitive Markets.....	444
2. Contradictions Within the RAR Proposal.....	448
B. <i>Jurisdictional Problems</i>	450
1. FERC's Legal Authority (According to FERC).....	451
2. FERC's Legal Authority (According to the United States Code).....	452
3. FERC's Legal Authority (According to the Case Law).....	454
III. Alternatives to RAR.....	456
A. <i>Require Call Options for Capacity</i>	456
1. Benefits of a Call-Option Regime.....	458
2. Shortcomings of a Call-Option Regime.....	458
B. <i>Raise Price Caps to the Value of Lost Load</i>	459
1. Spot Prices.....	459
2. Reserves.....	463
3. Better Than RAR, But Not First Best.....	464
Conclusion.....	465

Table of Acronyms

FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
ICAP	Installed Capacity
ISO	Independent System Operator
ISO-NE	ISO New England
ITP	Independent Transmission Provider
kW	Kilowatt
LOLP	Loss-of-Load Probability
LSE	Load-Serving Entity
MMM	Market Mitigation Measure
MW	Megawatt
MWh	Megawatt-hour
NOPR	Notice of Proposed Rulemaking
NYISO	New York ISO
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PURPA	Public Utility Regulatory Policies Act of 1978
RAR	Resource Adequacy Requirement
RTP	Real-Time Price
SMD	Standard Market Design
VOLL	Value of Lost Load

Introduction

Deregulation has hit upon hard times in the electricity markets. The public mood has reversed course, shifting from exuberance over the increased efficiencies deregulation promised to depression induced by the California meltdown.¹ The Federal Energy Regulatory Commission ("FERC"), though, is still attempting to nudge electricity markets toward competition. It recently released a Notice of Proposed Rulemaking ("NOPR")² outlining a Standard Market Design ("SMD") to which, if it is eventually promulgated as a rule, electricity markets throughout the country must conform.³ FERC intends to learn from the errors of deregulation's past instead of shrinking from the task altogether.

In California, one error among others⁴ was a shortage of generation capacity, a factor that arguably contributed to the breakdown in California's electricity market.⁵ While generation shortages have given

1 See, e.g., Phillip S. Cross, *State PUCs Show Split Personality*, PUB. UTIL. FORT., Feb. 15, 2003, at 10 ("While federal policy-makers push ahead with wholesale market reforms in the electricity sector, many at the state level now call for a cautious approach to protect consumers."); Timothy P. Duane, *Regulation's Rationale: Learning from the California Energy Crisis*, 19 YALE J. ON REG. 471, 539-40 (2002) (suggesting a return to command-and-control regulation in electricity markets to shield society from the risks of competitive markets).

2 While most government agencies use the acronym "NPRM" for Notice of Proposed Rulemaking, FERC employs "NOPR" instead.

3 *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55452 (published Aug. 29, 2002) (to be codified at 18 C.F.R. pt. 35) [hereinafter *Remedying Undue Discrimination*].

4 Blumstein et al. identify a number of causes for the California market's collapse besides shortage of generation capacity: "a retail price freeze that prevented supply and demand from equilibrating, exogenous increases in the prices of some key inputs, poor design of the electricity market, the exercise of market power by generation owners, and inept regulation." CARL BLUMSTEIN ET AL., *THE HISTORY OF ELECTRICITY RESTRUCTURING IN CALIFORNIA* 21 (Ctr. for the Study of Energy Mkts., Working Paper No. 103, 2002).

5 *Id.* at 22-23 ("During the period 1990 to 2000, load growth in California averaged about 1.2% per year After . . . 1991, capacity additions in California came nearly to a halt during the rest of the decade."). Joskow & Kahn show that, even after accounting for supply and demand factors affecting the California crisis, exercise of market power was responsible for a substantial portion of the price spikes. PAUL JOSKOW & EDWARD KAHN, *A QUANTITATIVE ANALYSIS OF PRICING BEHAVIOR IN CALIFORNIA'S WHOLESALE ELECTRICITY MARKET DURING SUMMER 2000* 2 (Nat'l Bureau of Econ. Research, Working Paper No. 8157, Mar. 2001) [hereinafter *JOSKOW & KAHN, A QUANTITATIVE ANALYSIS*]; Paul Joskow & Edward Kahn, *Identifying the Exercise of Market Power: Refining the Estimates I* (July 5, 2001) (unpublished manuscript, on file with Yale Journal on Regulation). *But see* Scott M. Harvey & William W. Hogan, *Further Analysis of the Exercise of Market Power in the California Electricity Market ii* (Nov. 21, 2001) (unpublished manuscript, on file with Yale Journal on Regulation) (arguing that claims about withholding such as Joskow & Kahn's are subject to a large margin of error, since they are based only on public information and not on more accurate proprietary data).

The FERC Staff, in detailing the causes of California's high electricity prices, "found significant market manipulation," though "significant supply shortfalls and a fatally flawed market design were the root causes of the California meltdown." FED. ENERGY REGULATORY COMM'N, *FINAL REPORT ON PRICE MANIPULATION IN WESTERN MARKETS: FACT-FINDING INVESTIGATION OF POTENTIAL MANIPULATION OF ELECTRIC AND NATURAL GAS PRICES ES1*, FERC Docket No. PA02-2-000 (Mar. 26, 2003), available at <http://ferris.ferc.gov/idmws/search/fercensearch.asp> [hereinafter *FINAL*].

way to a generation glut in the aggregate,⁶ there is reason to question the competitive market's ability to incentivize adequate generation resources on its own. First, competitive electricity markets are still in their infancy, and the optimism that led merchant generators to construct excessive generation capacity in response to projected shortages may give way to pessimism and too little construction of generation capacity the next time spot prices rise. In fact, as the economy has sputtered and load⁷ growth slowed,⁸ merchant generators have already halted construction that was still in the planning stage; although a generation surplus may exist for several years in some regions, it will not be as large, widespread, or prolonged as once thought.⁹

Second, the current surplus in generation capacity cannot be wholly attributed to competitive spot markets for wholesale electricity. Independent System Operators ("ISOs")¹⁰ in the Northeast run capacity markets (more specifically, auctions for Installed Capacity)¹¹ that supplement the spot prices generators receive with capacity payments intended to cover generators' fixed costs that go unrecovered in the spot market, provided the generators' capacity investments are efficient. In Installed Capacity ("ICAP") markets, Load-Serving Entities ("LSEs") are required to contract with enough generation capacity to cover the LSEs' load plus an additional reserve margin (commonly set at eighteen percent of load for large utilities)¹² in advance of delivery (often a month ahead). The ICAP that generators sell amounts to a pledge to bid a certain amount of electricity into the spot market at a future date, without specifying the buyer or the price. The individual LSE receives nothing in return for its capacity payment, since it still has to enter the spot market to purchase

REPORT ON PRICE MANIPULATION]. Although the FERC staff has access to proprietary data and reached conclusions similar to Joskow & Kahn's, Harvey & Hogan's warning about the value of public information still has some merit: The FERC Staff discovered a connection between manipulations of natural gas prices and high electricity prices that Joskow & Kahn had overlooked. *Compare* FINAL REPORT ON PRICE MANIPULATION, *supra*, at ES1-ES2, with JOSKOW & KAHN, A COMPARATIVE ANALYSIS, *supra*, at 30.

6 Gary L. Hunt & Fereidoon P. Sioshansi, *Is There a Capacity Glut, and How Long Will It Last?*, *ELECTRICITY J.*, Aug.-Sept. 2002, at 63; Steven A. Mitnick, *Generation Opportunities Remain Despite the Withering Attack of Superficial Analysis*, *ELECTRICITY J.*, Jan.-Feb. 2002, at 22.

7 "Load" simply denotes demand for electricity or "a customer that receives power from the electric system." STEVEN STOFF, *POWER SYSTEM ECONOMICS* 448 (2002).

8 Hunt & Sioshansi, *supra* note 6, at 66-67.

9 *Id.* at 71.

10 "An independent system operator is a nonprofit system operator" that schedules electricity transmission over a geographic area and "also runs a real-time balancing market and usually a day-ahead market of some type." STOFF, *supra* note 7, at 447. The three northeast ISOs are ISO New England ("ISO-NE"), the New York ISO ("NYISO"), and the Pennsylvania-New Jersey-Maryland Interconnection ("PJM").

11 Installed Capacity is "[g]enerating capacity that has been operational," though it need not be operational at present if it is "experiencing a planned or unplanned outage." *Id.* (emphasis omitted).

12 Remediating Undue Discrimination, *supra* note 3, ¶ 493.

electricity.¹³ The capacity payments a generator receives thus go toward its fixed costs; total spot market payments, which equal the energy-only price in the spot market multiplied by the quantity of electricity sold, should cover at least the generator's variable costs.

To combat uncertainty about the market's provision of generation, FERC's SMD NOPR proposes a Resource Adequacy Requirement ("RAR") with a goal similar to ICAP's—guaranteeing that enough generation exists to serve load. RAR, however, is not an attempt simply to repackage the ISOs' ICAP scheme. FERC intends to remedy shortcomings in ICAP markets, specifically ICAP's short-term nature and price volatility.

This Note will demonstrate, though, that RAR will not achieve FERC's goal of ensuring long-term resource adequacy. Even if it did, the RAR would undermine SMD's purpose, namely advancing toward a competitive electricity market, and it should be scrapped if FERC is serious about capturing the benefits of competition. Part I of the Note sets forth the rationale for capacity requirements in general and the RAR in particular. It explains how imperfections and market power in electricity markets lead some to call for capacity requirements, explores the characteristics of ICAP markets that FERC finds off-putting, and describes the RAR proposal. Part II evaluates the RAR from both substantive and jurisdictional perspectives. It demonstrates the tension between the RAR and SMD's overall goal as well as RAR's internal contradictions. Part II also surveys the relevant statutes and case law to see whether FERC has the power to promulgate the RAR or whether the RAR falls outside FERC's jurisdiction as an impermissible attempt to regulate generation. Part III describes alternative means of achieving resource adequacy. Call options for electricity, if mandated, could ensure long-term resource adequacy and encourage financial instruments that hedge price spikes. A superior alternative, however, would be to eliminate capacity requirements altogether and raise price caps to the value of lost load ("VOLL"), allowing demand response to discourage exercises of market power. In short, FERC should abandon the RAR.

¹³ LSEs can also satisfy the ICAP requirement by contracting for future delivery of electricity (that is, entering into a forward contract for electricity). In this case, LSEs do receive something in exchange for their bargain. Such contracting, though, occurs outside the ICAP market.

I. The Rationale Behind the Resource Adequacy Requirement

A. *The Unique Properties of Electricity and Their Implications for Electricity Markets*

Electricity's properties constrain electricity markets in distinctive ways. The physical laws governing electricity flows require that quantity demanded and supplied always be equal. Otherwise the grid malfunctions, and blackouts ensue. Ensuring equality of these quantities would be easier if demand were not highly inelastic. A holdover from the pre-deregulation era is the absence of real-time pricing;¹⁴ load pays a flat rate that averages the cost of electricity over a fixed period. Even if load were charged real-time prices, those price signals would have to be communicated to users in a timely fashion, and users' consumption would have to be measured in real time; the necessary technologies, however, are not installed at present and would require costly investment on the part of the regulator, load, or LSEs.¹⁵ As a result, load does not respond to high prices at peak hours by reducing consumption, because it pays the same price for consumption at peak hours as it does for consumption at any other hour. The consequences are especially dire if peak load is greater than the supply of electricity, forcing the ISO to shed load.

Like demand, short-run supply is inelastic. Electricity cannot be stored, and the fixed costs of capacity are substantial, such that firms do not retain much excess capacity.¹⁶ Supply expands only through the construction of new generation, and that takes at least one year to come on line from start to finish.¹⁷

The equality constraint and the inelasticity of supply and demand create opportunities for market-power abuses even when no single generator has a large market share. To exercise market power, a generator need only be pivotal. If the gap between supply and demand, however

14 Severin Borenstein, *Frequently Asked Questions About Implementing Real-Time Electricity Pricing in California for Summer 2001*, at 3 (Mar. 2001) (unpublished manuscript, on file with Yale Journal on Regulation) ("The economics of demand charges made more sense under the old regulatory regime. The concept was to charge customers for their contribution to the need to build additional peaking capacity This makes much less sense in a deregulated wholesale market where demand increases result in significant increases in wholesale price even before the system gets right up to its capacity.").

15 *Id.* at 5-7 (estimating that operationalizing real-time pricing for California load whose peak usage is above 200kW would cost \$30 million). See also Michael Jaske, *Practical Implications of Dynamic Pricing*, in *DYNAMIC PRICING, ADVANCED METERING, AND DEMAND RESPONSE IN ELECTRICITY MARKETS* 31, 39-45 (Hewlett Found. Energy Series, Oct. 2002) (describing the various metering and telecommunications systems required to operationalize demand response).

16 Adam B. Jaffe & Frank A. Felder, *Should Electricity Markets Have a Capacity Requirement? If So, How Should It Be Priced?*, *ELECTRICITY J.*, Dec. 1996, at 55.

17 Frank A. Felder, *"An Island of Technicality in a Sea of Discretion": A Critique of Existing Electric Power Systems Reliability Analysis and Policy*, *ELECTRICITY J.*, Apr. 2001, at 28.

small, cannot be filled without a particular generator, that generator can bid far above marginal cost and still be paid its bid, if not more. Its bid becomes the market-clearing price if no other generator submits a higher bid that is accepted.¹⁸ Since demand does not respond by decreasing consumption and since supply cannot expand for a time, a pivotal generator can reap monopoly profits. Withholding can perform the same trick. Generators take a small amount of generation offline or, for part of their capacity, submit bids high enough that they will never be accepted. Once a generator becomes pivotal, either through its own or other generators' withholding, it can force the market-clearing price to a level that at the very least permits recovery of the opportunity cost of the generation withheld.

1. Price Caps and Market Mitigation

Because of demand's inelasticity and the potential for market-power abuse, FERC and the ISOs have instituted measures aimed at curbing artificially high spot prices and limiting excessive price volatility. Price caps decrease generators' incentives to exercise market power and dampen wide swings in prices. To make economic or physical withholding of generation worthwhile, generators must increase prices enough to offset the opportunity cost of keeping some capacity out of the market. Price caps make this more difficult, since generators will not withhold if the opportunity cost is greater than the added revenue the price cap permits.¹⁹

Price caps also smooth price spikes by limiting their height. Although discouraging market-power abuses seems a boon, the benefit from decreased price fluctuations is less clear.²⁰ The conventional wisdom appears to conflate volatility and high spot prices, without articulating costs unique to the former.²¹ FERC claims that volatility discourages customers from entering into long-term contracts for electricity and thus prevents customers from obtaining price certainty.²² FERC's argument

18 This assumes that the market is not pay-as-bid and instead that the highest accepted bid sets the market price paid to all generators. I do not consider the pay-as-bid case, because FERC proposes a single market-clearing price regime in its SMD NOPR. *Remedying Undue Discrimination*, *supra* note 3, ¶ 204 n.118 (proposing a single market-clearing price regime because it encourages generators to bid at marginal cost and because it incentivizes demand response).

19 STOFT, *supra* note 7, at 171.

20 Associating price caps with decreased price fluctuations is inaccurate in some circumstances even if the price caps bind. The variance of spot prices could rise after the introduction of price caps. If shortages occur more frequently in a price-cap regime, the price may be driven to the cap sufficiently often to increase the variance in spot prices compared with a price-spike regime. Even in such a scenario, though, the range of spot prices would still be smaller.

21 See, e.g., Janet Gail Besser et al., *The Political Economy of Long-Term Generation Adequacy: Why an ICAP Mechanism Is Needed as Part of SMD*, *ELECTRICITY J.*, Aug.-Sept. 2002, at 54.

22 *Remedying Undue Discrimination*, *supra* note 3, ¶ 98.

seems to equate volatility and uncertainty about long-term price trends, since in the presence of volatility alone customers would be more likely to enter long-term contracts to secure a single price for electricity.

Because price caps apply regardless of whether price spikes result from scarcity or from market power, sometimes the caps will suppress prices' ability to signal the need for more capacity. A common price cap, for instance, is \$1000 per megawatt hour ("MWh"). Even if no market-power abuses occur, the spot price likely must exceed \$1000/MWh several times over if generators are to recover their fixed costs in the absence of a capacity market.²³

Besides price caps, ISOs have implemented market mitigation measures ("MMMs") to combat market-power abuses that occur at prices below the cap. In theory, these MMMs screen abuses of market power from price increases due to scarcity and therefore do not suppress scarcity prices. For example, consider the New York ISO's ("NYISO's") conduct and impact test. The NYISO compares a generator's bid to reference levels calculated using that generator's bids from the previous ninety days. When the current bid exceeds the reference level by the lesser of 300 percent or

23 Report of John J. Boland & Javier Inon on behalf of Dynegy Power Marketing, Inc. at 10, Remedying Undue Discrimination, FERC Docket No. RM01-12-000 (Feb. 19, 2003), available at <http://feris.ferc.gov/idmws/search/fercgensearch.asp> [hereinafter Report of Boland & Inon] (calculating that in the absence of capacity markets a price cap ranging from \$16,150/MWh to \$32,000/MWh would be necessary to ensure a loss-of-load probability ("LOLP") of one day in ten years). Paul Joskow argues that revenues from the spot market in ISO-NE between 1999 and 2002 demonstrate that the spot market will not generate enough scarcity rents to maintain conventional levels of reliability. Comments of Professor Paul L. Joskow at 28-39, Remedying Undue Discrimination, FERC Docket No. RM01-12-000 (Jan. 10, 2003), available at <http://feris.ferc.gov/idmws/search/fercgensearch.asp>. In contrast to Boland & Inon's position, Joskow claims that raising the price cap is not a solution, since even the current \$1000/MWh cap has hardly ever been binding; if price caps were causing revenue deficiencies, one would expect spot prices to reach the cap more often than six hours per year on average. *Id.* at 34-35.

Although Joskow's evidence lends support to his conclusion about the inadequacy of spot prices as scarcity signals, it does not prove that Joskow is correct. For one, spot prices between 1999 and 2002 may be signaling a surplus of capacity in New England. Joskow does not believe this is the case, but he admits that demonstrating so is difficult. *Id.* at 37. Second, Joskow's analysis of spot prices does not account for capacity payments generators received from ISO-NE's ICAP market. *Id.* at 33-34, 38-39. While the marginal cost and, equivalently, the competitive price of ICAP are zero when generation capacity is sufficient to serve load, during a shortage ICAP's competitive price is the levelized cost of a marginal generation unit. Although spot prices even under shortage conditions may not generate enough scarcity rents to cover the fixed costs of marginal generation, that result need not reflect a shortcoming in the spot market but instead would occur because capacity payments from the ICAP market cover the balance of generators' fixed costs. To prove that spot prices are inappropriate signals, Joskow would have to show that the existence of a capacity market does not affect the level of spot prices, and he neither makes nor provides sufficient evidence for such a claim.

Furthermore, Joskow's claim about spot-market revenues is limited to marginal generators, namely combustion turbines, and does not apply to baseload units. *Id.* at 34, 36. Combustion turbines are the costliest units to run. As a result, when the spot price just covers a peaking unit's variable costs, cheaper baseload units, such as combined-cycle generators, will receive a spot price that exceeds their variable costs. Joskow's findings do not show that these inframarginal revenues fall short of baseload units' fixed costs.

\$100/MWh, the NYISO considers mitigation. If a generator is suspected of engaging in physical rather than economic withholding, then the NYISO weighs mitigation when the current quantity withheld is greater than the lesser of ten percent or 100MW of a unit's capability or the lesser of five percent or 200MW of the generator's capacity across all units. These thresholds are designed to separate cases of scarcity pricing from exercises of market power. Even if the thresholds obtain, the NYISO consults with the generator to seek a competitive justification that would obviate mitigation of the suspect bids.²⁴ Alternatively, if the thresholds obtain but the bids have little impact on market-clearing prices, then no mitigation is applied.²⁵ If firms cannot profit from increasing their bids or from taking capacity offline, then they are much less likely to be exercising market power.

Unlike price caps, the MMMs do not blindly suppress scarcity prices, since they attempt to distinguish between scarcity-pricing behavior and market-power abuses. As the NYISO's conduct and impact test shows, though, discretion plays a large role in separating competitive from non-competitive pricing;²⁶ the market monitor must decide without the help of bright-line rules whether bids that surpass the thresholds are competitively justified or whether those bids impact market-clearing prices. Inevitably the market monitor will mistakenly identify competitive bidding behavior as a market-power abuse that must be mitigated or, conversely, will erroneously permit market-power abuses that are justified to the monitor's satisfaction.²⁷ Although FERC's SMD NOPR does not explain why FERC believes that MMMs suppress scarcity prices,²⁸ FERC is likely worried about the former category error.²⁹ One other motivation for FERC's concern may be the transaction costs generators incur when justifying their bidding behavior to the ISO's market monitor.³⁰ Even if such costs are not

24 Affidavit of David B. Patton, Ph.D. on behalf of the New York Independent System Operator ¶¶ 17-35, *In re* New York Independent System Operator, FERC Docket No. ER01-3155-002 (Mar. 20, 2002), available at <http://ferris.ferc.gov/idmws/search/fercensearch.asp>.

25 *Id.* ¶¶ 36-40.

26 See John Farr & Frank A. Felder, *A Critique of Existing Market Performance Monitoring and Mitigation Policies*, *ELECTRICITY J.*, July 2002, at 16 (claiming that the NYISO's balancing test is "opaque and politically driven").

27 The market monitor would also not detect market-power abuses when the bids involved do not surpass the thresholds. Such errors, however, are not due to the market monitor and would probably occur rarely given the low level of the thresholds.

28 Remediating Undue Discrimination, *supra* note 3, ¶ 468.

29 FERC may also be concerned that vigilant market monitoring that would lead to false positives (finding market-power abuses when they do not occur) more often than false negatives (not identifying market-power abuses when they occur). Otherwise the revenues generators receive from market-power abuses that go unnoticed may offset the losses they incur from not always being able to charge scarcity prices.

30 See Farr & Felder, *supra* note 26 ("[T]he process of mitigating bids in load pockets has proven time consuming and prone to litigation; the process might best be characterized as a 'miniature rate case.'").

substantial, their existence will distort generators' bids to some extent. On the whole, though, MMMs are unlikely to suppress scarcity prices to the same degree that price caps do.

2. Insufficiency of Price-Spike Signals

Apart from concerns about market power and suppression of scarcity prices, spot-market prices, according to FERC, would not signal the need for new generation in time for it to come online.³¹ The lag in generation construction prevents supply from responding quickly to changes in spot-market prices and thus results in short-run inelasticity of supply.

Given that short-run inelasticity characterizes a number of industries that require capital equipment with similar lag times, FERC's concern seems solipsistic. The peculiarities of electricity, however, may justify FERC's claim. First, in other industries with significant supply-side lags, demand responds to increased prices, and the market equilibrates. In the case of electricity, political, economic, and regulatory constraints have foreclosed implementation of demand response.³² The only solution to a shortage of electricity is to shed load.³³

Second, in other industries, while manufacturers wait for new capital equipment to come online, they can satisfy demand by importing goods from regions not experiencing a shortage. For electricity, even when spot prices reflect scarcity, physical limits on transmission lines may prevent enough electricity from being imported into areas of high demand to satisfy load.³⁴ (Such areas of high demand that are coupled with binding transmission constraints on imports are known as "load pockets.") The only means of satisfying demand in a load pocket is either to build more transmission lines (which itself involves a lag) or to construct additional generation within the pocket.

Despite the electricity markets' unique characteristics, FERC's argument that spot prices will signal shortages too late to prevent them is not wholly convincing. Merchant generators that do not recognize trends in spot prices and load growth will forego profits that other generators more sophisticated in predicting future generation needs will capture. Perhaps no merchant generator could interpret market trends accurately

31 Remediating Undue Discrimination, *supra* note 3, ¶ 461.

32 See Borenstein, *supra* note 14; see also Severin Borenstein, *The Theory of Demand-Side Price Incentives*, in DYNAMIC PRICING, ADVANCED METERING, AND DEMAND RESPONSE IN ELECTRICITY MARKETS 5, 29 (Hewlett Found. Energy Series, Oct. 2002).

33 Two types of shortages can exist in electricity markets. A *reserve shortage* occurs when the supply of electricity can serve the entire load but is smaller than the load combined with the reserve margin. An *overall shortage* exists when the supply of electricity is less than load.

34 Transmission lines have physical limits on the amount of electricity they can carry. When those limits are binding, the line is "congested."

due to the infancy of electricity markets and uncertainty about the regulatory response to them, but that would be a claim about a nascent industry and not about spot prices per se.³⁵

Further, FERC's concern about the lag in constructing generation capacity may be somewhat anachronistic. While combustion turbines' lead time is twelve to eighteen months, they can be dismantled, moved, and reassembled in approximately six months' time.³⁶ Granted, combined-cycle generators still require two to three years to construct, and FERC worries that a market solution to generation adequacy would be biased against such lower-cost generation because of its longer lead time.³⁷ Mobile combustion turbines, though, might be a viable market solution. Even after the turbines are moved to a site needing generation, merchant generators would still build combined-cycle generators, both to realize cost efficiencies and to make the turbines available to areas that will experience future shortages.³⁸

3. Relation to Capacity Requirements

The conventional response to the problems posed by suppressed scarcity prices, a lack of demand response, and the long lead times in generation construction is to impose a capacity requirement in conjunction with a capacity market. Since price caps and market mitigation in the spot market limit generators' ability to recover their fixed costs, the payments generators receive in capacity markets should suffice to cover any fixed costs not recovered in the spot market, as long as the generators have not overbuilt their capacity. A capacity requirement that also encourages long-term resource adequacy would ensure that enough generation capacity is online to prevent shortages due to spot prices' inability to signal impending problems with sufficient lead time.³⁹

35 Cf. Joskow, *supra* note 23, at 22 (“[I]mmature, incomplete and illiquid forward markets for risk hedging . . . reduce[] the ability of investors in new generating capacity to hedge market risks and increase[] their financing costs above what they would be if consumer and supplier risk preferences could be better matched.”).

36 Felder, *supra* note 17, at 28; Paul Farrell, *Turbines Generate Questions: Concern, Not Complaints, Over Plans for Inlet Power-Boost Source*, NEWSDAY, Aug. 7, 2000, at A27. See also *Online Shopping*, PUB. UTIL. FORT., Sept. 1, 2001, at 58 (describing Enporion's online auction of “ready-to-install” turbines intended for generation companies that need increased generation “in a matter of months”).

37 Remedying Undue Discrimination, *supra* note 3, ¶ 466.

38 In addition to distributed generation, wind power has a lead time of only a few months (four or five, to be exact), though wind power is much less reliable than combustion turbines. Peter Asmus, *California Crisis: The Best Argument Yet for Wind Power*, ELECTRICITY J., Apr. 2001, at 44.

39 One means of ensuring long-term resource adequacy is to have a high reserve margin, since capacity prices will increase whenever insufficient capacity exists to satisfy the reserve margin even if load growth is not on track to surpass available generation for some time. Such a high reserve margin, though, could be incorporated into the spot market and thus does not necessitate a capacity requirement or a market. RAR embodies an alternative method, namely setting capacity requirements

B. ICAP's Inadequacies

Several drawbacks to the ICAP market, one of them mentioned in FERC's SMD NOPR, militate against using ICAP to ensure resource adequacy. First, ICAP markets without price caps could experience extreme swings in price. When a surplus of ICAP exists, its marginal cost (and competitive price) is zero.⁴⁰ The generator, after all, promises only to bid a specified amount of capacity into the spot market; the generator is not agreeing to deliver electricity to a particular LSE or to bid at a particular price. When a shortage of ICAP exists, however, the cost of supplying additional capacity is the levelized fixed cost of new generation,⁴¹ which leads to high ICAP prices given the expensive nature of generation capacity's fixed costs. The fact that ICAP trades are made only a month in advance of the date when the generator must bid its capacity into the spot market exacerbates the price spikes.

Second, ICAP markets are susceptible to exercises of market power.⁴² Consequently, ISOs have employed price caps in ICAP markets, thereby suppressing scarcity prices and defeating ICAP's purpose of compensating generators' fixed costs of efficient investments.⁴³ ISO New England ("ISO-NE"), for instance, penalizes LSEs that are deficient in ICAP.⁴⁴ The penalty constitutes an implicit price cap, since no LSE would pay more than the penalty for ICAP. ISO-NE's penalty is \$6.15 per kilowatt-month ("kW-month"), equivalent to the levelized fixed cost of a peaking unit.⁴⁵ Such a cap is likely too low to achieve a loss-of-load probability ("LOLP") of one day in ten years.⁴⁶ Sometimes the ICAP price will be less than the

years in advance. Additionally, for reasons discussed *infra* Subsection III.B.2, allowing consumers' preferences to dictate the level of reliability is better than having a central decision-maker set the reserve margin.

40 Amended Filing of ISO New England, Inc. at 15, ISO New England, Inc., FERC Docket No. EL00-62-001 (May 8, 2000), available at <http://ferris.ferc.gov/idmws/search/fercgensearch.asp>.

41 In capacity markets that impose a penalty for ICAP deficiencies, the price will equal the penalty when total ICAP is less than required capacity. See STOFT, *supra* note 7, at 182-84.

42 Amended Filing of ISO New England, Inc. at 8-10, ISO New England, Inc., FERC Docket No. EL00-62-001 (May 8, 2000), available at <http://ferris.ferc.gov/idmws/search/fercgensearch.asp>.

43 Remediating Undue Discrimination, *supra* note 3, ¶¶ 544-46.

44 New England Power Pool and ISO New England, Inc., 100 FERC 61,287, ¶ 13, 97-98 (2002) (order accepting in part and modifying in part Standard Market Design filing and dismissing compliance filing).

45 New England Power Pool, 100 FERC 61,287 ¶ 13, 97-98; E-ACUMEN, FINAL REPORT ON THE LEVELIZED ANNUAL COST OF CONSTRUCTING A NEW PEAKING RESOURCE IN NEW ENGLAND 6 (2001), available at http://www.iso-ne.com/special_studies/Other_Special_Studies/New_England_Peaking_Resource_Cost_e-Acumen_12-10-01.pdf (last visited Apr. 14, 2003).

46 See, e.g., Benjamin F. Hobbs et al., *Installed Capacity and Price Caps: Oil on the Water, or Fuel on the Fire?*, 14 ELECTRICITY J., July 2001, at 26 (finding that an equilibrium price of \$7/MWh for ICAP is necessary to achieve an LOLP of one day in ten years when a \$1000/MWh price cap prevails in the spot market). New estimates of the cost of installed capacity suggest that the numbers used in Hobbs et al.'s model were too low. Report of Boland & Inon, *supra* note 23, at 7-10.

cap,⁴⁷ and thus the average payments generators receive in the ICAP market will not cover the fixed costs of efficient peaking units.⁴⁸ Whether generators actually install peaking units despite being unable to recover peaking units' fixed costs in the ICAP market will depend on spot prices. Market-power abuses or a shortage of operating reserves could lead to energy-only payments that exceed peaking units' variable costs enough to incentivize investment that ensures an LOLP of one day in ten years.⁴⁹

Third, ICAP requires LSEs and generators to incur the transaction cost of trading in yet another market. Unless generators and LSEs enter into forward contracts to satisfy the ICAP requirement, which for most generators and LSEs seems unlikely,⁵⁰ they still must trade in the spot market: Generators must trade to fulfill their ICAP commitment, and LSEs to purchase deliverable electricity.

C. FERC's Alternative: A Resource Adequacy Requirement

Dissatisfied with ICAP markets,⁵¹ FERC has proposed a Resource Adequacy Requirement to ensure long-term resource adequacy. Instead of requiring LSEs to secure capacity a month ahead of delivery, FERC suggests a time horizon of at least two years ahead but permits regions to set a longer time horizon if they wish.⁵² Under RAR, Independent Transmission Providers ("ITPs")⁵³ forecast future load and allocate a portion to each LSE based on the ratio of the LSE's load to the regional load.⁵⁴ Another entity, the Regional State Advisory Committee, determines the reserve margin to be added to the LSE's load assignment, although FERC has set a floor of twelve percent.⁵⁵

47 Recall that, during a surplus of ICAP, its marginal cost—and its competitive price—is \$0.

48 If the peaking units were inframarginal in the spot market, then they could be recovering the remainder of their fixed costs in the spot market. Since peaking units are the most expensive units to run, they are more likely to be on the margin in the spot market than be inframarginal. See Joskow, *supra* note 23, at 34-36.

49 Although the Hobbs et al. model takes scarcity spot prices into account, it abstracts from the effect market-power abuses and an operating reserve requirement have on spot prices. Report of Boland & Inon, *supra* note 23, at 5-8. The same is true of Boland & Inon's update of the Hobbs et al. model. *Id.* at 8-11. In contrast, Boland & Inon's simulation of FERC's SMD, *infra* note 86, does account for the effect of market power and an operating reserve requirement on spot prices. *Id.* at 5, 14-17, A10 (assuming that prices spike to the lesser of consumers' willingness to pay or the \$1000/MWh cap whenever operating reserves fall below the largest unit's capacity and that a penalty applies whenever operating reserves are less than the operating reserve requirement).

50 The short time span between the ICAP and spot markets makes it seem unlikely that parties that do not contract forward in the absence of ICAP will shift course and start to do so in the presence of an ICAP market, since insurance against movements in spot prices thirty days after the ICAP market is run seems a small benefit.

51 See Remediating Undue Discrimination, *supra* note 3, ¶¶ 543-47.

52 *Id.* ¶¶ 523-24.

53 ITPs are the successors of ISOs; the differences between them are insignificant here.

54 Remediating Undue Discrimination, *supra* note 3, ¶ 474.

55 *Id.* ¶¶ 489-90, 493.

Enforcement of the RAR occurs after an LSE is deficient in real time, and the severity of the penalty depends on how much of a shortage existed. If an LSE is deficient in a year in which a shortage occurs, the ITP levies a fine on top of the spot price of any electricity the LSE took from the spot market during shortage conditions.⁵⁶ The ITP, however, limits the penalty to the quantity by which the LSE “falls short of meeting its resource adequacy requirement,”⁵⁷ and the penalty, which never exceeds \$1000/MWh, is graduated according to the severity of the system’s shortfall:⁵⁸ If the shortage exceeds the system’s reserve margin, requiring the ITP to shed load, deficient LSEs will be curtailed first,⁵⁹ though only up to the amount of their deficiency.⁶⁰ For LSEs that take electricity from the spot market despite a curtailment order, the ITP will assess a \$1000/MWh penalty.⁶¹

II. Implementation Difficulties

A. *Substantive Problems*

1. Tension with Competitive Markets

The SMD NOPR’s overriding purpose is “to harness the benefits of competitive markets for the nation’s electric energy customers.”⁶² FERC’s RAR proposal, however, seems at loggerheads with SMD’s goal; RAR is reminiscent of the old, vertically-integrated regulated-utility model that FERC intends to leave behind. First, to achieve long-term resource adequacy, under RAR an ITP must forecast future load several years in

⁵⁶ *Id.* ¶ 534. Besides the spot price, LSEs also pay transmission charges, but that does not affect my point here.

⁵⁷ *Id.* ¶ 528. Since LSEs are allocated a share of *projected* load *plus* a reserve margin, the LSEs are deficient even if they secured capacity equal to their load but short of the amount the ITP allocated to them.

The consequences for being deficient apparently vary depending upon whether a deficient LSE later cures its deficiency. In a footnote, FERC says that an LSE that fails to submit a satisfactory resource plan after being assigned its share of forecasted load would be subject to the penalty rate during a shortage in the year for which it was supposed to plan. *See id.* ¶ 527 n.227. The penalty, though, applies only to LSEs that use the spot market to purchase more electricity than the resources they had secured. *Id.* ¶ 529. (It is unclear whether the reserves portion of an LSE’s load allocation would always be a factor affecting the quantity subject to the penalty.) Thus, LSEs that submit unsatisfactory resource plans can still remedy their inadequacy later and not be penalized. In fact, FERC encourages LSEs to make amends, as long as they do so before the spot market is run. *Id.* ¶ 528 n.229. The implications of this enforcement scheme are discussed *infra* Subsection II.A.2. *See also* Joskow, *supra* note 23, at 48-49 (“[A]s I read the NOPR, the forward contracting requirement is very easy to evade.”).

⁵⁸ *Id.* ¶ 530.

⁵⁹ *Id.* ¶ 527.

⁶⁰ *Id.* ¶ 477.

⁶¹ *Id.* ¶ 534.

⁶² *Id.* ¶ 1.

advance and evaluate LSEs' plans for providing adequate resources to meet the projected load.⁶³ This appears very similar to the regulated planning process of vertically-integrated utilities. In fact, FERC's proposal is closer to the command-and-control model than is ICAP, with its shorter time horizon that makes such planning unnecessary. Second, after an ITP has forecasted future load, a Regional State Advisory Committee will set the required reserve margin, which is added to forecasted load when calculating LSEs' load assignments.⁶⁴ Although FERC lists various factors the Advisory Committee should take into account when setting the reserve margin, ultimately the Committee has discretion to choose the reserve margin. Again, this central planning runs counter to the competitive approach,⁶⁵ which would let consumers' preferences dictate the level of reliability via the market.

Besides RAR's similarities to the old central-planning model for electricity generation, it stunts the development of demand response, which is generally recognized as the key to a stable, competitive market.⁶⁶ In a deregulated market, exercising market power becomes much more profitable when demand response is absent; the profits possible from withholding increase when demand cannot curb price spikes. Aside from market-power abuses, during shortage conditions a market without demand response would fail to clear, necessitating regulatory intervention: Once scarcity prices exceed the value of electricity consumption, the regulator should shed load.

Although the RAR permits demand response to participate as a resource that LSEs may use to satisfy their load assignments,⁶⁷ eligible demand response must pre-commit. According to the SMD NOPR, demand response must be "verifiable," and the ITP "must have confidence that the demand response resource will be able to contribute when called on during a shortage."⁶⁸ The two forms of demand response that expressly satisfy RAR are biddable demand reduction and interruptible load.⁶⁹ Under biddable demand reduction, load agrees to drop off the system once pre-determined price levels are reached.⁷⁰ To qualify as interruptible, load

63 Remediating Undue Discrimination, *supra* note 3, ¶¶ 485-87, 501.

64 *Id.* ¶¶ 489-90.

65 *See id.* ¶ 481 ("The proposed approach is like the traditional reserve margin requirement imposed by states on monopoly utilities.")

66 *See, e.g.,* Alfred E. Kahn, *The Adequacy of Prospective Returns on Generation Investments Under Price Control Mechanisms*, *ELECTRICITY J.*, Mar. 2002, at 37 (claiming that demand response is necessary to establish competitive electricity markets); LARRY E. RUFF, *ECONOMIC PRINCIPLES OF DEMAND RESPONSE IN ELECTRICITY* 6-9 (2002) (describing the benefits of demand response).

67 Remediating Undue Discrimination, *supra* note 3, ¶¶ 507-08.

68 *Id.* ¶ 517.

69 *Id.*

70 *Id.*

must agree to interruptions under defined shortage conditions in exchange for a year-round lower price.⁷¹ Even if load meets these requirements, it may still be ineligible if transmission constraints prevent delivery of the released generation to the area using it to satisfy the RAR.⁷²

Due to the conditions load must satisfy to qualify as demand response under RAR, the requirement will incentivize less demand response than would a regime with real-time prices (“RTPs”). The stochastic character of a particular load’s needs may prevent it from participating in RAR demand response, since RAR requires load to pre-commit and thus predict what its future needs will be when called upon to back down. In an RTP regime, in contrast, load can decide to back down contemporaneously with the price spikes, at which point the load’s needs are known. For some load, at pre-determined price levels the benefit of backing down (namely, the savings from not paying for electricity) will always be larger than the cost (namely, ceasing whatever productive activity the electricity facilitated), and such load would participate in RAR demand response. For other load, the tradeoff requires estimating expectations and taking risk aversion into account. Load whose expected benefit from backing down is greater than the expected cost of doing so may still refuse to pre-commit if the load is averse to risk. In fact, particularly risk-averse load or load whose expected cost of backing down is greater than its expected benefits will not participate in RAR demand response even though it would sometimes reduce demand in an RTP regime. Under an RTP regime, instances would arise when the benefit unambiguously surpassed the cost, and at that point demand would back down, regardless of whether it would pre-commit to doing so. Further complicating matters, transmission constraints will prevent load from providing RAR demand response if the constraints sometimes prevent delivery of electricity from the demand response to the load using that demand response to satisfy the RAR.⁷³ Again, load would not have to pre-commit under RTPs, so that probabilistic transmission constraints would not preclude load from providing demand response. Additionally, since generation freed up by RTP demand response would not have to serve load at a pre-determined location (as is the case with RAR demand response), the probability that transmission constraints would hinder delivery of demand response would be lower for RTP than for RAR demand response.

71 *Id.* ¶ 518.

72 *Id.* ¶ 519.

73 FERC’s SMD NOPR devotes only a single sentence to probabilistic transmission constraints. *Id.* (“If load in an area ‘buys’ demand reduction from another area . . . , the transmission needed to deliver the freed-up generation to the load that relies on it must be available.”). Since at least some non-zero probability that transmission constraints will be binding always exists, FERC must have some other measure of availability in mind. If a zero probability of binding transmission constraints were the standard, no load would qualify as RAR demand response, except vis-à-vis itself.

All this assumes that the probability distributions of shortages, electricity prices, and the timing of shortages are available to load. Given the lack of historical data on reliability under a competitive (or partially-competitive) regime, however, load might not be able to estimate these probability distributions. In that case, the differential between demand response under RAR and under scarcity pricing would be even larger. Load whose expected benefits of participating in RAR demand response are actually larger than its expected costs may fail to participate simply because the load cannot estimate the expectations.

Although total demand response under RTPs would be greater than under RAR, one can only speculate how large the differential would be, since the inquiry is counterfactual. Data on RTP demand response already exist,⁷⁴ but data on RAR demand response do not. Nevertheless, it seems plausible that the differential would be large and that for most load the expected cost of reducing demand would exceed the expected benefit⁷⁵ or the risk involved would be too great, especially if pre-commitment under RAR must occur years or months ahead.⁷⁶

Furthermore, capacity markets established in response to RAR would likely include price caps that, as in today's ICAP markets, suppress scarcity prices and thereby inhibit demand response's development.⁷⁷ Without caps, price fluctuations are larger, and price spikes potentially

74 Georgia Power Company has an RTP demand-response program that includes both day-ahead demand response and hour-ahead demand response, neither of which involves pre-commitment. Mike O'Sheasy, *Real Time Pricing at Georgia Power Company*, in DYNAMIC PRICING, ADVANCED METERING, AND DEMAND RESPONSE IN ELECTRICITY MARKETS A1-A2 (Hewlett Found. Energy Series, Oct. 2002). The program is open only to large customers. *Id.* at A1. Even so, demand response "can reach as high as 800-1,000MW, or 5% of [Georgia Power Company's] peak," *id.*, which should be sufficient to produce a long-run market equilibrium. STOFF, *supra* note 7, at 143. Load on hour-ahead demand response is significantly more elastic than load on day-ahead demand response. *Id.* at A2 (showing that the largest customers, who are on the hour-ahead program, exhibit a price elasticity of -0.2 at moderate prices and -0.28 at high prices, while customers on the day-ahead program exhibit a price elasticity of -0.02 at moderate prices and -0.06 at high prices). Besides Georgia Power Company, Gulf Power Company has instituted a residential demand response program. *Gulf Power's Residential Service Variable Price Option*, in DYNAMIC PRICING, ADVANCED METERING, AND DEMAND RESPONSE IN ELECTRICITY MARKETS B1 (Hewlett Found. Energy Series, Oct. 2002). Participating customers do not have to pre-commit and have on average reduced consumption 22% during high price periods. *Id.* at B5, B8.

75 For instance, if a firm conducts the majority of its business at a particular time of day and does not want to be interrupted then, it cannot make its availability for RAR demand response contingent on the time of day. The firm could, of course, increase the price level at which it is willing to be curtailed to reflect the value of electricity during its busiest period, but that would decrease its overall demand response.

76 The fact that Georgia Power Company maintains an RTP demand-response program in addition to an interruptible demand-response program, which requires pre-commitment, suggests that the additional participation in RTP demand response warrants the cost of running a second demand-response program. GEORGIA POWER COMPANY, ELECTRICITY PRICING, at http://www.southerncompany.com/gapower/pricing/gpc_rates.asp?mnuOpco=gpc&mnuType=com&mnuItem=ps#business (last visited Mar. 30, 2003).

77 RAR allows but does not require ITPs to establish capacity markets. Remedying Undue Discrimination, *supra* note 3, ¶ 549.

limitless, giving load more incentive to invest in technologies it needs to respond to RTPs,⁷⁸ because then load can reduce its electricity costs to a greater degree by taking electricity from the grid at non-peak times and backing down at peak times. In fact, the presence of price caps in the spot market is one of the main reasons FERC is proposing the RAR: Such caps suppress scarcity pricing, and therefore the spot market alone cannot assure resource adequacy. Without RAR or a comparable capacity requirement, the current price-cap regime would have to be overhauled, and consequently there would be even greater incentive for demand response to develop.

In addition to stunting demand response, RAR creates an inefficient pooling effect across different types of load. The pooling effect inheres in any capacity requirement that includes a reserve margin, since a central entity cannot tailor resource reliability to suit every agent's preference. In the RAR regime, depending on the forecasts of future load and the required reserve margin, elastic demand will want less reliability than is mandated, or highly inelastic demand will prefer more reliability than is mandated, or both.⁷⁹ Elastic demand thus subsidizes load that prefers more reliability, while inelastic demand is not permitted to pay for and receive the level of reliability it prefers. Even though this cost is not unique to RAR, it is a cost of imposing RAR.

2. Contradictions Within the RAR Proposal

Not only is RAR a step back toward the era of central planning, but the RAR proposal is also internally contradictory. First, payments from an RAR capacity market will not incentivize the generation necessary to achieve an LOLP of one day in ten years, the standard measurement of reliability.⁸⁰ Although RAR does not require the establishment of a capacity market,⁸¹ unless LSEs fulfill the RAR entirely through forward contracts or call contracts,⁸² LSEs will have to purchase capacity in a separate market. As the ICAP markets in the northeastern ISOs have demonstrated,⁸³ capacity markets are no more immune from market-power

78 For a description of the various metering and telecommunications systems required to operationalize RTP, see Jasko, *supra* note 15, at 39-45.

79 Kahn, *supra* note 66, at 42.

80 One day in ten years is the standard for reliability that the electricity industry has adopted. See STOFT, *supra* note 7, at 182.

81 Remediating Undue Discrimination, *supra* note 3, ¶ 549.

82 Even if LSEs purchased all of their electricity through long-term forward contracts or call contracts, FERC's penalties for RAR violations would limit the price an LSE would willingly pay. As discussed below, though, LSEs have little incentive under RAR to enter forward contracts.

83 See, e.g., Amended Filing of ISO New England, Inc. at 9-12, ISO New England, Inc., FERC Docket No. EL00-62-001 (May 8, 2000), available at <http://feris.ferc.gov/idmws/search/fercgensearch.asp>.

abuses than are spot markets.⁸⁴ Consequently, ITPs will likely implement price caps in the capacity markets they run. Even if they do not, FERC's suggested penalties for violating the RAR would function as implicit price caps. The penalties range from \$500/MWh to \$1000/MWh,⁸⁵ but to achieve an LOLP of one day in ten years, the energy-deficiency penalty should be higher, possibly around \$20,000/MWh.⁸⁶ As a result, RAR will not achieve long-term resource adequacy; the capacity payments, in addition to any scarcity rents from the spot market, will not cover the fixed costs of the peaking units needed to ensure an LOLP of one day in ten years.

Second, RAR does not encourage *long-term* resource adequacy; instead of FERC's imposing penalties for resource deficiencies a certain number of months before real-time delivery, RAR is enforced *ex post*. FERC proposes to penalize only those LSEs that do not secure enough resources to satisfy their share of the regional needs and only in the amount by which they fall short and to the extent that they take electricity from the spot market.⁸⁷ LSEs that formulate unsatisfactory plans to meet their resource requirement or that are deficient even a few days prior to a shortage are not penalized as long as they contract for enough resources or deliverable electricity or both before the day-ahead spot market is run.⁸⁸ In the case of an overall shortage, whether LSEs could cure their deficiencies

84 Hobbs et al., *supra* note 46, at 31.

85 Remedying Undue Discrimination, *supra* note 3, ¶¶ 530, 534. FERC specifically asked for comments on its proposed penalties, *Id.* ¶ 530, so they may well be subject to change.

86 Report of Boland & Inon, *supra* note 23, at 11-17. Boland & Inon use data from the 2001 PJM market to calculate how large the RAR penalty must be to induce LSEs to pay for the capacity necessary to achieve an LOLP of one day in ten years when the levelized fixed cost of a peaking unit is \$73,000/MW-year. *Id.* at 8, 10, 16. Boland & Inon's model assumes that the spot price equals the marginal cost of the most expensive unit until operating reserves fall below the largest unit's capacity (1170 MW in the model and in PJM), at which point the spot price spikes either to consumers' willingness to pay or to the spot-price cap of \$1000/MWh, whichever is lower. *Id.* at 5, 15, A10. A penalty is applied whenever operating reserves are less than 7.5%. *Id.* at 15. Boland & Inon derive the following result: Even if the peaking units receive revenues from price spikes, ancillary services, and operating reserves, the penalty must be \$19,031/MWh irrespective of the reserve shortage's severity. *Id.* at 15-17. In the case when peaking units do not receive ancillary revenues, the penalty increases to \$20,631/MWh. *Id.* at 17.

Boland & Inon's assumption that the spot price equals the marginal cost of the most expensive unit when operating reserves are greater than the largest unit's capacity may be unrealistic if generators are not price takers. See Peter Cramton, Report on Competitive Bidding Behavior in Uniform-Price Auction Markets on Behalf of Duke Energy at 15-19, San Diego Gas & Electric Company, FERC Docket No. EL00-95-075 (Mar. 20, 2003). Spot prices in Boland & Inon's model, however, spike after operating reserves drop below 1170MW without any restraint on the part of a market monitor, suggesting that the scarcity revenues from these price spikes may offset any shortcomings from Boland & Inon's assumption of marginal-cost pricing.

87 See *supra* note 57. These penalties potentially apply to an LSE that, while deficient, takes from the spot market only an amount that generation under contract with the LSE agreed to deliver to the spot market, in compliance with RAR. Remedying Undue Discrimination, *supra* note 3, ¶ 505. A similarly deficient LSE that entered bilateral contracts instead would not be penalized. *Id.* ¶ 528.

88 Remedying Undue Discrimination, *supra* note 3, ¶ 528.

just two days ahead and thereby avoid curtailment is unclear, though the SMD does not expressly bar them from doing so.⁸⁹ Even if deficient LSEs take from the spot market during a curtailment, FERC's proposed penalty is only \$1000/MWh,⁹⁰ which is low compared to one estimate of the penalty required to achieve an LOLP of one day in ten years.⁹¹

RAR's *ex post* enforcement and implicit price caps doom FERC's achieving its long-term resource adequacy goal.⁹² Not only does RAR not require LSEs to obtain resources by any particular date, but LSEs also have little incentive to contract with resources as far ahead as FERC would like. If spot and short-term prices reflected scarcity and consequently were volatile, then LSEs would have reason to hedge those prices by entering into long-term forward contracts for electricity,⁹³ coincidentally furthering FERC's resource adequacy goals. Given FERC's small penalties and the spot market's price caps, though, short-term price spikes will be limited even in the face of shortages. Consequently, LSEs will have little incentive to hedge against short-term price movements, and resource adequacy will not be achieved via long-term energy contracts.

Thus, under RAR, achieving resource adequacy depends on participants' responses to short-term prices.⁹⁴ Ironically, FERC proposed the RAR because of short-term spot prices' supposed inability to signal generation needs in a timely fashion.⁹⁵ Under FERC's rationale, RAR should fail: Short-term prices will not signal generation needs in time for merchant generators to respond, and at times resources will be inadequate to serve load.

B. *Jurisdictional Problems*

Even if RAR could achieve FERC's goals, the Federal Power Act ("FPA") expressly places electricity generation outside FERC's jurisdiction. Whether that restriction prevents FERC from enforcing RAR

89 *Id.* ¶ 532.

90 *Id.* ¶ 534.

91 Report of Boland & Inon, *supra* note 23, at 15-17. Under RAR, if the ITP cannot maintain reliability when an LSE takes from the spot market after being ordered to curtail, the cost to the LSE of taking from the spot market would be much higher than the \$1000/MWh plus the spot price. Since all LSEs would suffer from the resulting blackout, though, the rebellious LSE would not fully internalize the social cost of its behavior.

92 Larry E. Ruff, Assuring Resource Adequacy: Concepts, Options and the SMD, Slide 20, Presentation to the Mass. Elec. Restructuring Roundtable (Oct. 18, 2002), http://www.ksg.harvard.edu/hepg/Standard_Mkt_dsgn/Ruff_resource.adequacy_10-18-02.pdf.

93 Since competitive wholesale markets are relatively new, firms may still be biased against entering long-term forward contracts while they are learning how the market operates.

94 See Initial Comments of John D. Chandley and William W. Hogan on the Standard Market Design NOPR at 92-95, FERC Docket No. RM01-12-000 (Nov. 11, 2002), available at <http://ferris.ferc.gov/idmws/search/fercgensearch.asp>.

95 See *supra* Subsection I.A.2.

entirely is debatable, but it certainly prevents FERC from using RAR to mandate generation expansion.

1. FERC's Legal Authority (According to FERC)

Although FERC does not cite any legal authority to justify the RAR in particular, it does explain the legal basis for SMD as a whole. FERC invokes Sections 205 and 206 of the Federal Power Act ("FPA") as its statutory authority.⁹⁶ The former prohibits undue discrimination in transmission of electricity in interstate commerce or in wholesale sales in interstate commerce,⁹⁷ which is more relevant to FERC's transmission reforms than to its capacity requirement.⁹⁸ Section 206 is more on point. It gives FERC power to remedy any "rule, regulation, [or] practice" resulting in rates and charges that are "unjust, unreasonable, unduly discriminatory or preferential" by promulgating a "just and reasonable" replacement.⁹⁹ If this section were the end of the matter, FERC could decide that not having a capacity requirement results in electricity prices that are unjust or unreasonable (due, say, to a generation shortage), and it could implement a capacity requirement as the necessary remedy. Besides the FPA, FERC could have cited the Energy Policy Act of 1992. Section 722 of the Act gives FERC authority to require wholesale transmission rates that "promote the economically efficient . . . generation of electricity."¹⁰⁰ The argument would be that RAR is necessary to ensure wholesale transmission rates that achieve efficient generation, since creating new generation is one means of eliminating load pockets and the higher transmission charges that accompany them.¹⁰¹

In addition to relying on its statutory authority, FERC looks to the case law. According to FERC, the courts have made clear that FERC's "authority to remedy undue discrimination and anticompetitive effects is broad."¹⁰² Since a capacity shortage not only exacerbates market power but also results from FERC's attempts to control market power in the spot

96 Remediating Undue Discrimination, *supra* note 3, ¶ 100.

97 16 U.S.C. § 824d(b) (2000) ("No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.").

98 To the extent that building new generation relieves transmission congestion, Section 205 may be relevant to RAR.

99 16 U.S.C. § 824e (2000).

100 16 U.S.C. § 824k (2000).

101 More generation in a load pocket will decrease the amount of electricity that must be imported into the load pocket, thereby relieving transmission congestion.

102 Remediating Undue Discrimination, *supra* note 3, ¶ 101. For support, FERC cites *Gulf States Utils. Co. v. FPC*, 411 U.S. 747 (1973); *Associated Gas Distribs. v. FERC*, 824 F.2d 981 (D.C. Cir. 1987); *City of Huntingburg v. FPC*, 498 F.2d 778 (D.C. Cir. 1974). *Id.* ¶ 101 n.72-73.

markets, RAR appears to be an authorized remedy for anticompetitive effects in the electricity market.

2. FERC's Legal Authority (According to the United States Code)

FERC's authority over generation is subject to a large exception that goes unmentioned in the SMD NOPR. Section 201 of the FPA declares that FERC "shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy."¹⁰³ Other sections of the FPA that touch upon generation fail to extend FERC's powers to mandating construction of new generation. Section 202 permits FERC to create "regional districts for the voluntary interconnection and coordination of facilities for the generation" of electricity,¹⁰⁴ but it restricts such limited intervention in generation to instances in which the utility consents.¹⁰⁵ Even if FERC finds it in the public interest to order a public utility to interconnect with another utility, it cannot "compel the enlargement of generating facilities for such purposes."¹⁰⁶ When planning for shortages, FERC may order a public utility to issue a report on its contingency plans in case of a shortage, but that power does not extend to ordering a public utility to prepare in any particular way for a shortage.¹⁰⁷ Similarly, according to Section 311, FERC can investigate generation at any time and report the results to Congress, but it is not authorized to take any actions in response to its investigation.¹⁰⁸ Most importantly, Section 207 of the FPA, which specifically authorizes FERC to issue orders to ensure adequate service, expressly prevents FERC from ordering "the enlargement of generating facilities" for adequacy purposes.¹⁰⁹

When Congress wanted FERC to encourage construction of certain forms of generation and thereby improve reliability, it "specifically

¹⁰³ 16 U.S.C. § 824(b) (2000).

¹⁰⁴ 16 U.S.C. § 824a(a) (2000).

¹⁰⁵ See *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 12 (D.C. Cir. 2002) (noting that Section 202 "make[s] clear that Congress intended coordination and interconnection arrangements be left to the 'voluntary' action of the utilities").

¹⁰⁶ 16 U.S.C. § 824a(b) (2000).

¹⁰⁷ 16 U.S.C. § 824a(g) (2000). Although the FPA does not expressly prohibit FERC from ordering a public utility to prepare for a shortage, neither does it authorize FERC to do so. And courts "will not presume a delegation of power based solely on the fact that there is not an express withholding of such power." *Atlantic City*, 295 F.3d at 9 (quoting *Am. Petroleum Inst. v. EPA*, 52 F.3d 1113, 1120 (D.C. Cir. 1995)). See also *New York v. FERC*, 535 U.S. 1, 18 (2002) ("[A]n agency literally has no power to act, let alone pre-empt the validly enacted legislation of a sovereign State, unless and until Congress confers power upon it." (quoting *La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374 (1986))).

¹⁰⁸ 16 U.S.C. § 825j (2000).

¹⁰⁹ 16 U.S.C. § 824f (2000).

provided” for such jurisdiction, as Section 201 permits,¹¹⁰ by passing the Public Utility Regulatory Policies Act of 1978 (“PURPA”). Congress’s findings accompanying PURPA do not cite any delinquency on FERC’s part as a reason for passing PURPA, so presumably Congress was not attempting to force FERC to exercise jurisdiction it already had.¹¹¹ Even under PURPA’s section pertaining to reliability, FERC is not authorized to promulgate industry standards of reliability; FERC may only recommend such standards to the industry.¹¹² Although PURPA on its own does not prove that FERC lacks jurisdiction over generation, it further supports the claim that Congress did not intend that FERC’s jurisdiction over generation extend beyond the narrow limits set in the FPA, unless Congress legislates to the contrary.

FERC’s counterargument to a claim that RAR falls within the generation exception to FERC’s jurisdiction would likely be that RAR does not mandate generation expansion. FERC does not care how LSEs maintain generation adequacy. LSEs can satisfy the requirement by implementing demand response or, if they are in a load pocket, by building new transmission. All FERC is doing is requiring LSEs to ensure that enough supply exists to serve their load.

Such a rationale, though, would permit FERC to evade the FPA’s explicit restrictions through a sleight of hand, since RAR has the effect of mandating generation construction to satisfy LSEs’ load assignments. Granted, LSEs could invest in demand reduction and new transmission to serve their load rather than build more generation capacity.¹¹³ But the quantity of demand response under the RAR regime will likely not be substantial given FERC’s requirement that demand pre-commit to qualify as demand response.¹¹⁴ Additionally, the eminent domain authority needed to construct transmission likely precludes LSEs from relying on increased transmission, since politicians are not keen on having new transmission lines sited in their districts or states (the “not-in-my-backyard” phenomenon).¹¹⁵ Given these constraints, in many cases LSEs’ only means of satisfying the RAR will be to pay for or construct new generation. If

110 16 U.S.C. § 824(b) (2000) (FERC “shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter . . .”).

111 See 16 U.S.C. § 2601 (2000).

112 16 U.S.C. § 824a-2(c) (2000).

113 Although for the sake of argument I treat demand response as though it were within FERC’s jurisdiction, it may fall within the retail distribution exception to FERC’s jurisdiction. See 16 U.S.C. § 824(b) (“The Commission . . . shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, . . . over facilities used in local distribution . . .”).

114 See *supra* Subsection II.A.1.

115 An example of the political hurdles that block transmission expansion is Connecticut Attorney General Richard Blumenthal’s opposition to the Long Island Power Authority’s transmission cable that connects Long Island to southern Connecticut. See Linda L. Randell & Bruce L. McDermott, *Chronicle of a Transmission Line Siting*, PUB. UTIL. FORT., Jan. 1, 2003, at 34.

FERC can bypass the FPA's constraints by promulgating a regulation that could be complied with either by activities over which FERC has jurisdiction or by activities over which FERC does not have jurisdiction, and if the former activities are theoretically possible but practically infeasible, then for that issue the FPA would lose any bite it otherwise had vis-à-vis FERC. Unless the FPA's exceptions to FERC's jurisdiction are meaningless, the RAR falls outside FERC's jurisdiction.¹¹⁶ Or at the very least, FERC may not penalize an LSE for deficiencies whose only practical cure is generation construction, a fuzzy standard that would hinder enforcement.

3. FERC's Legal Authority (According to the Case Law)

No case is directly on point, since FERC's RAR represents a recent foray into resource adequacy on FERC's part. The Supreme Court, though, has recognized the generation exception to FERC's jurisdiction even when it has not been central to the case.¹¹⁷ More importantly, the D.C. Circuit Court of Appeals recently refused to recognize FERC's attempts to interpret the FPA broadly when the statutory language does not grant FERC power to act as it did.¹¹⁸ In *Atlantic City*, FERC claimed jurisdiction under Section 203 of the FPA over the reorganization of a pre-existing power pool into an ISO. The Court, quoting the FPA, noted that Section 203 provides that "[n]o public utility shall sell, lease, or otherwise dispose of jurisdictional facilities whose value exceeds \$50,000" without receiving FERC's approval.¹¹⁹ FERC argued that the reorganization amounted to a disposition and thus required FERC's approval. The D.C. Circuit, however, rejected FERC's characterization. The reorganization did not entail any "transfer of ownership or even physical operation of [the utilities'] facilities."¹²⁰ Not only that, but FERC's interpretation of disposition was also "an unexplained departure from past FERC practice."¹²¹ FERC's claim that Section 203 applied was therefore invalid, and the reorganization did not require FERC's approval. This holding does

116 FERC could also argue that the Regional State Advisory Committees are implementing the RAR and rely on the states' recognized jurisdiction over generation to avoid the FPA's bar to FERC's jurisdiction. The Advisory Committees' involvement, though, is limited. While they set the exact level of resource adequacy and the planning horizon for the region, FERC determines certain minimum levels of adequacy as well as the penalties and enforcement mechanism applied to deficient LSEs. Remedying Undue Discrimination, *supra* note 3, ¶¶ 493, 524, 527. The same goes for FERC's intent to have states enforce the LSEs' load obligations. *Id.* ¶ 533. Even if states are enforcing the RAR, FERC retains regulatory authority by determining the RAR's content.

117 See *New York v. FERC*, 535 U.S. 1, 21 (2002) (recognizing that generation facilities are excepted from FERC's jurisdiction).

118 *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

119 *Id.* at 11 (emphasis omitted).

120 *Id.*

121 *Id.* at 12.

not bode well for any creative label FERC might use to bring RAR within its jurisdiction.¹²²

FERC may not be at as great a disadvantage as *Atlantic City* suggests, since a recent Supreme Court case went so far as to expand FERC's jurisdiction beyond FERC's own interpretation (albeit on significantly different facts).¹²³ In *New York v. FERC*, the controversy centered on FERC's imposition of open-access requirements on unbundled retail transmissions that are interstate transmissions.¹²⁴ Before 1996, FERC had refrained from exercising jurisdiction over retail transmission, and New York sought to block FERC's reversal of this sixty-year-old practice, a change that threatened New York's as well as other states' regulatory powers. Nevertheless, the Court held that, since retail transmission is not one of the exceptions carved out of the FPA, FERC has jurisdiction over unbundled retail transmission in interstate commerce. Furthermore, the Court said, were FERC to find undue discrimination in the retail electricity market, it would also have jurisdiction over bundled retail transmission in interstate commerce,¹²⁵ a claim from which even FERC had shied away.

In *New York v. FERC*, though, FERC's jurisdiction explicitly followed from Section 201 of the FPA, which grants FERC jurisdiction over "transmission of electric energy in interstate commerce."¹²⁶ Additionally, the Court noted that, should FERC exercise authority over bundled retail sales, FERC would raise thorny jurisdictional issues, since FERC has jurisdiction only over the interstate transmission component of the bundled sale.¹²⁷ Applied to RAR, *New York v. FERC* suggests that, even if FERC has authority to implement RAR to the extent that it increases demand response and transmission construction, FERC cannot enforce RAR when generation construction is necessary to cure LSEs' deficiency.

122 On remand, FERC has attempted to bolster its claim that creation of the PJM ISO, as well as entry into and exit from the ISO, is a disposition that requires FERC's approval. *Pennsylvania-New Jersey-Maryland Interconnection*, 101 FERC ¶ 61,318 (2002). FERC claims that the court's interpretation of "other disposition" reflects FERC's failure to explain its position well enough. *Id.* ¶ 43. FERC argues that, because the PJM ISO—unlike its predecessor PJM Power Pool—is "independently governed," "directs the operation of the transmission facilities," and "is prohibited from taking direction from any transmission owner," the reorganization from a power pool into an ISO qualifies as a disposition within the meaning of Section 203. *Id.* ¶ 44-46. Whether the D.C. Circuit will be sympathetic to FERC's arguments remains to be seen. *Atlantic City Electric Company* is unswayed and has filed a mandamus petition claiming that FERC's order on remand simply repeats arguments that the D.C. Circuit has already rejected. *Petition to Enforce the Mandate at 2, Atlantic City Elec. Co. v. FERC* (D.C. Cir.) (No. 97-1097).

123 *New York v. FERC*, 535 U.S. at 21.

124 *Id.* at 4-5.

125 *Id.* at 22, 26. A bundled charge includes both the cost of the electricity and the cost of its delivery. An unbundled charge decouples the two and charges load separately for the electricity and the transmission.

126 16 U.S.C. § 824(b) (2000).

127 *New York v. FERC*, 535 U.S. at 26.

III. Alternatives to RAR

Before implementing a capacity requirement that will be ineffective and will stunt the growth of competitive wholesale markets for electricity, FERC should explore the alternatives. Given ICAP's own drawbacks, that is not an alternative I consider. Neither do I consider a retooled version of RAR that actually provides long-term resource adequacy; such an RAR would discourage demand response, since demand response would have to pre-commit far ahead of real time. Rather, I examine two possibilities: (1) requiring LSEs to purchase enough call options for electricity to guarantee that they can serve their entire load and (2) replacing the current price-cap regime with a spot-price cap equal to the value of lost load ("VOLL"), such that generators recover all of their fixed costs in the spot market.

A. *Require Call Options for Capacity*

Some have suggested replacing capacity markets with a market for call options and mandating that generators sell and LSEs acquire enough call options to cover future capacity needs not otherwise serviced through forward contracts.¹²⁸ For each call option, the generator would agree either to sell up to a specified quantity of electricity at a particular price (the strike price) should the spot price ever exceed the strike price or to pay the purchaser the difference between the strike and spot prices. Consider a hypothetical call option whose strike price is \$100/MWh and whose quantity is 500MWh. If the spot price reaches \$150/MWh and the LSE calls its option, the generator can either supply the LSE with 500MWh of electricity at \$100/MWh or pay the LSE \$25,000. As for the LSE, it pays the option price, which is analogous to a capacity payment. Unlike a contract securing ICAP, though, the individual LSE receives something in return, namely a ceiling on its risk.¹²⁹

The parameters of a call option for capacity include the time horizon, the strike price, the quantity, and a possible penalty for non-delivery. The range these parameters can take depends on the potential for market-power abuse and the regulator's goals. For the time horizon, to ensure long-term resource adequacy, the option would have to be effective some years into the future. Either the option's time horizon would have to extend several years, or the option would not take effect for some years into the future. LSEs would be required to have sufficient call options throughout the time

¹²⁸ See Ignacio J. Perez-Arriaga, et al., *A Market Approach to Long-Term Security of Supply*, 17 IEEE TRANSACTIONS ON POWER SYSTEMS 349, 352 (2002) [hereinafter *Market Approach*]; Ignacio J. Perez-Arriaga, et al., *If Pay-As-Bid Auctions Are Not a Solution for California, Then Why Not a Reliability Market?*, ELECTRICITY J., May 2001, at 47.

¹²⁹ Recall that a generator offering capacity in a capacity market only commits to sell that capacity into the spot market, not to a particular LSE or at a particular price.

period during which the regulator wishes to ensure resource adequacy. Otherwise an LSE could opt out of the requirement by purchasing a call option that lasts, say, one hour during an entire year.

Since LSEs and generators will have to contract for their call options by a particular point before the options take effect, the ITPs would likely run a residual market for those LSEs that have not purchased their call options prior to the deadline. The ITPs would have to use MMMs in the residual market to prevent generators from abusing their market power vis-à-vis the LSEs. For LSEs contracting outside the residual market, dislocations due to market-power abuses are unlikely to occur, since an LSE that does not want to be taken advantage of can always wait until the residual market is run before fulfilling the call-option requirement. As a result, the MMMs would be limited to the residual market.

In addition to the time horizon, regulatory intervention would be necessary to prevent opting out through the strike price. The regulator should set a cap on the strike price. Otherwise, generators and LSEs could agree to a strike price high enough that the option would never be called, driving the option's price to zero, effectively permitting generators and LSEs to opt out of the requirement. Even with a cap, MMMs would be necessary to prevent generators from exercising market power by manipulating the strike price.

Another parameter of the call option is the quantity the generator offers to sell at the strike price. Since economic and physical withholding are the only concerns the regulator would have with quantity, the regulator's involvement should be limited to market mitigation.

Last, a penalty could attach to the call options if the generators that sell them fail to provide energy when called upon. Although Perez-Arriaga et al. advocate a penalty,¹³⁰ it seems superfluous. Since generators are obligated to pay LSEs the difference between the strike and spot prices if they do not provide the electricity themselves, the generators are internalizing the entire cost of their behavior. If the price cap in the spot market is set at VOLL, and the VOLL underestimates a particular LSE's cost of backing down,¹³¹ that LSE could contract for a penalty that reflects its idiosyncratic VOLL and that applies when the LSE cannot obtain electricity elsewhere due to a curtailment. A penalty applied uniformly would, in all likelihood, not provide the level of adequacy that many market participants desire, as exemplified by the pooling effect.¹³²

130 Perez-Arriaga et al., *Market Approach*, *supra* note 128, at 354.

131 Why the spot price should not exceed VOLL is explored *infra* Subsection III.B.1.

132 See *supra* text accompanying note 79.

1. Benefits of a Call-Option Regime

If the enforcement mechanisms were implemented correctly, call options would guarantee long-term resource adequacy and would also encourage the development of financial instruments that LSEs may use to hedge future spot prices. The option's strike price effectively creates a price cap for the LSE that purchased it. Unlike a regulated price cap, though, the market determines how much LSEs value price stability, since the premium an LSE would pay for the option would be inversely related to the strike price. Market forces may not completely determine this competitive "price cap," however, because a cap on the strike price would function as a floor on the option's price to the extent the option's price is inversely related to the strike price.

Additionally, call options decrease the risk associated with peaking units, which are called upon only when the level of load is very high. Such units may not be called upon to provide electricity for long periods of time, and then, for example, when abnormal weather patterns lead to an increase in load, the peaking units are called and reap huge revenues. Call options smooth that revenue stream; the cost of peakers is no longer concentrated in a short time period that no one can anticipate exactly. Consequently, with an active option market, peakers may attract investors for whom the risk was previously unpalatable. A capacity market, though, would similarly smooth peakers' revenue streams; capacity payments would take into account the likelihood that generators must bid their peakers into the spot market to fulfill their obligations. With options, though, individual LSEs receive the benefit of hedging risk, whereas in capacity markets LSEs benefit only indirectly from generators' commitment to bid into the spot market.

2. Shortcomings of a Call-Option Regime

Although the growth of financial instruments that hedge future spot prices might be advantageous, artificial growth in response to regulatory requirements would be counterproductive. Granted, by requiring that all market participants buy and sell in the option market, a call-option requirement may correct market failure resulting, for instance, from uncertainty about market liquidity.¹³³ Given the lack of historical data on spot-price trends in competitive electricity markets, though, generators

¹³³ Such uncertainty might have discouraged investment in necessary setup costs for the call-option market. See also Joskow, *supra* note 23, at 22 ("[I]mmature, incomplete and illiquid forward markets for risk hedging . . . reduce[] the ability of investors in new generating capacity to hedge market risks and increase[] their financing costs above what they would be if consumer and supplier risk preferences could be better matched.").

may have trouble pricing call options, and as a result the requirement may simply force generators to sell call options they otherwise would not, regardless of liquidity concerns, and to price the options rather high, especially if the call options are sold far ahead of when they take effect.¹³⁴

Another response may be to increase activity in forward contracts for electricity as an alternative to call options. Assuming the call-option requirement did not correct prior market failure that discouraged forward contracting,¹³⁵ to the extent that the call-option requirement spurs such contracting, it represents a regulatory distortion rather than a market optimum.

Also, call options add a layer of complexity that a market monitor may have difficulty peeling away when it applies its MMMs. The market monitor cannot have just one screen for the price, one for quantity, one for the time horizon, and another for the strike price. One screen must integrate all four. Otherwise generators could adjust the four parameters without tripping the threshold for any individual parameter while accomplishing the same overall effect as a change that would trip an individual parameter's threshold.

Last, a call-option regime would create inefficiencies if a central decision-maker has to assign LSEs a particular portion of estimated future load. In that case, a call-option requirement would resemble a command-and-control regulatory structure, similar to RAR. The call-option regime, however, may avoid specifying an individual LSE's load assignment by instituting market-oriented penalties that discourage LSEs from free-riding on the resources other LSEs secure via option contracts.¹³⁶

B. *Raise Price Caps to the Value of Lost Load*

1. *Spot Prices*

Although a call-option requirement may be superior to RAR, a better alternative exists. Raising price caps to VOLL is, perhaps paradoxically, the key to curing current market imperfections that RAR is meant to

¹³⁴ Since the same uncertainty would exist in a capacity market where capacity must be assured several years before the capacity is bid into the market, this shortcoming does not favor a capacity requirement over a call-option requirement, assuming the capacity requirement would achieve long-term resource adequacy.

¹³⁵ Not having an option market may have discouraged parties from contracting forward. For one, generators could not buy call options to hedge their forward positions and LSEs could not buy put options to do the same. An active call option market, developed in response to the requirement, would provide generators with easy access to hedging vehicles and may also encourage the development of a market for put options. Also, since forward contracts serve as substitutes for call options, the call-option requirement may spur generators and LSEs to contract forward, something they perhaps avoided previously due to regulatory uncertainty or a lack of liquidity in forward markets.

¹³⁶ See *infra* Subsection III.B.2.

address. The major fear about this alternative is that market imperfections, if not constrained by price caps below the VOLL, will lead to disasters such as the California crisis. The California debacle, however, is more the exception than the rule: In California, poorly designed market rules encouraged market-power abuses that led to blackouts and prices far above marginal cost.¹³⁷ In normally functioning markets price spikes occur for short periods of time and constitute a relatively small proportion of load's overall bill.¹³⁸

Although raising price caps will likely increase the effect of price spikes on load's bills, allowing prices to reflect scarcity conditions is central to a smoothly-functioning competitive market. Scarcity prices will spur investment in demand response. They increase the marginal benefits of demand response, and consequently load has more incentive to pay for technologies that facilitate communication of RTPs and that meter load's usage in real-time.¹³⁹ As demand becomes more elastic in response to real-time pricing, peak load decreases, non-peak load increases, and changes in supply have a smaller effect on price.

Of course, price caps cannot be completely eliminated. Until demand response develops, load could exceed supply, electricity markets would fail to clear, and the price for electricity would exceed the cost of not having it. Curtailing load then becomes more efficient than paying the spot price to obtain enough deliverable electricity to satisfy load. For now, prices should be capped at the VOLL, the opportunity cost of energy consumption. Having VOLL as a price cap leaves enough flexibility in the market price to induce demand response¹⁴⁰ and prevents prices at which social welfare is unequivocally suboptimal. Once demand response is sufficiently sophisticated to control price spikes, then FERC should

137 FINAL REPORT ON PRICE MANIPULATION, *supra* note 5, at ES1-ES3; BLUMSTEIN ET AL., *supra* note 4, at 22-26; Paul Joskow, *California's Electricity Crisis*, 17 OXFORD REV. OF ECON. POL'Y 365, 380-81 (2001); Paul Joskow & Edward Kahn, *Identifying the Exercise of Market Power: Refining the Estimates 5* (July 2001) (unpublished manuscript, on file with Yale Journal on Regulation). *But see* Scott M. Harvey & William W. Hogan, *On the Exercise of Market Power Through Strategic Withholding in California i-ii* (Apr. 24, 2001) (unpublished manuscript, on file with Yale Journal on Regulation) (arguing that market-power abuses may not be to blame for the California crisis, especially in light of higher fuel costs, environmental constraints, and capacity shortages). The FERC Staff Report, however, undercuts Harvey & Hogan's analysis; the report documents multiple market-power abuses, including some in the natural gas market that were intended to affect electricity prices. FINAL REPORT ON PRICE MANIPULATION, *supra* note 5, at ES1-ES3 ("[M]arkets for natural gas and electricity in California are inextricably linked, and . . . dysfunctions in each fed off one another during the crisis.").

138 Larry E. Ruff, *Demand Response: Reality Versus "Resource,"* ELECTRICITY J., Dec. 2002, at 13.

139 *See supra* note 78.

140 Australia's VOLL, for instance, was estimated at between 15,000AUD/MWh and 25,000AUD/MWh (approximately \$9000/MWh and \$15,000/MWh, respectively), substantially higher than current price caps of \$1000/MWh. STOFF, *supra* note 7, at 140.

eliminate the VOLL price cap as well, leaving such valuation to the market's more accurate determination.

Estimating VOLL is easier said than done, but estimation errors are unlikely to have much of a negative effect, especially if VOLL is overestimated. Complications in estimating VOLL arise because VOLL varies depending on customer type, the time of the loss, and the duration of the loss.¹⁴¹ The losses that commercial end users suffer from an outage during peak hours are much higher than the losses residential end users suffer,¹⁴² and blackouts affect all users indiscriminately. Outages at peak hours cause higher losses, since businesses activities are usually in full swing during peaks. Last, the first few moments of an outage are disproportionately costly due to the damage that the mere occurrence of an outage causes; if the outage is prolonged, though, the cost rises again as businesses are forced to close and as vandalism becomes more likely.¹⁴³ Despite these complicating factors, efforts at estimating VOLL have been made. The costs of past outages, such as New York City's 1977 power failure,¹⁴⁴ surveys of customers' valuations of reliability,¹⁴⁵ and applications of "common sense"¹⁴⁶ are three different methods used. The results are far ranging, falling between \$2,600/MWh and \$22,000/MWh.¹⁴⁷ All of these figures, however, are much higher than current spot-price caps, and fortunately the effects of miscalculating VOLL (which seems inevitable) "are not dramatic."¹⁴⁸ The upper bound for the cost to load of setting VOLL at \$15,000/MWh when its actual value is \$1500/MWh is only 3.3 percent of the total cost of power, according to Stoft.¹⁴⁹

FERC's motivation for proposing RAR is not limited to the effects of price caps. FERC also claims that market mitigation suppresses scarcity prices.¹⁵⁰ Although the MMMs attempt to screen market-power abuses from instances of scarcity pricing,¹⁵¹ some false positives will inevitably occur. Further, the transaction costs of justifying scarcity pricing to the

141 STOFT, *supra* note 7, at 156-57.

142 Peter Cramton & Jeffrey Lien, Value of Lost Load 3 (Feb. 14, 2000) (unpublished manuscript, on file with Yale Journal on Regulation) (citing a Canadian study finding that outages cost commercial and industrial users \$17,000/MWh of peak demand compared to \$2000/MWh of peak demand for residential users, when measured in 1999 dollars).

143 See STOFT, *supra* note 7, at 156; Cramton & Lien, *supra* note 142, at 1.

144 See Cramton & Lien, *supra* note 142, at 1.

145 See *id.* at 2.

146 See STOFT, *supra* note 7, at 160.

147 See *id.* at 160; Cramton & Lien, *supra* note 142, at 4. Note that Cramton & Lien's figures were originally measured in 1999 dollars. I updated them to 2002 dollars, using the Consumer Price Index inflation calculator. U.S. DEP'T OF LABOR, CONSUMER PRICE INDEX INFLATION CALCULATOR, at <http://data.bls.gov/cgi-bin/cpicalc.pl> (last visited Apr. 4, 2003).

148 STOFT, *supra* note 7, at 154.

149 *Id.* at 164.

150 Remedying Undue Discrimination, *supra* note 3, ¶ 461.

151 See *supra* Subsection I.A.1.

market monitor will also impede recovery of fixed costs from the spot market. Market mitigation cannot be eliminated, however, because the peculiarities of electricity sometimes create opportunities for generators, even ones with small market shares, to game the market and profit from withholding. Instead, FERC should suggest changes to MMMs designed to minimize transaction costs and the occurrence of false positives. For instance, market thresholds should take into account the duration of price spikes and should not use percentage changes in parameters that may disadvantage small generators.¹⁵² Additionally, thresholds should be tied to the load-generation ratio. As supply (forced and unforced generation) becomes tighter or as load increases secularly, the thresholds should increase, and as the ratio decreases the thresholds also should decrease. Including all installed capacity prevents generators from abusing market power by increasing the load-generation ratio through withholding. Using a system's winter or summer peaks rather than cyclical measures of load preserves the bright-line nature of the thresholds; if the measure of load changed too frequently, generators would be uncertain about what bids surpass the thresholds and, as a result, would not always submit bids reflecting scarcity.

Even if changes in MMMs are not the solution, market mitigation's effect on scarcity prices is likely much smaller than that of a \$1000/MWh price cap. Market mitigation is not blindly applied and instead responds to competitive justifications for price spikes. Also, in addition to false positives, false negatives will occur when screening market-power abuses; revenues from false negatives may offset the effects false positives have on scarcity prices. Last, all capacity markets to date have included either price caps or market mitigation, so whether a capacity requirement remedies price caps' and market mitigation's deleterious effects on scarcity pricing is unclear.

FERC's final concern is that spot prices will not signal the need for generation with sufficient lead time to construct new generation.¹⁵³ FERC's worry, however, may be a bit anachronistic.¹⁵⁴ Merchant generators have discovered how to reduce the lag in bringing new generation online by relocating already constructed combustion turbines. Also, to the extent that the lag is a symptom of merchant generators' inexperience in interpreting trends in spot prices, over time they should

152 See James F. Wilson, *The New York ISO's Market Power Screens, Thresholds, and Mitigation: Why It Is Not a Model*, *ELECTRICITY J.*, Aug.-Sept. 2000, at 25-27 (claiming that the NYISO's percentage thresholds disadvantage small generators, who are likely to trigger the percentage thresholds by taking inconsequential amounts of generation offline when larger generators would not trigger the percentage thresholds at such low quantities). Thresholds measured in terms of megawatts and megawatt-hours would not raise the same concerns.

153 Remediating Undue Discrimination, *supra* note 3, ¶ 461.

154 See *supra* Subsection I.A.2; sources cited *supra* note 36.

become more adept at anticipating load growth. Even if my view proves overly optimistic, uncertainty due to the infancy of competitive electricity markets would also hinder generators' ability to estimate the revenues generated by capacity committed three years before the spot market is run. Although central decision-makers such as the ITPs project load growth, they hold no apparent advantage over merchant generators at predicting that far ahead. What's more, the RAR currently relies on short-term prices to signal new investment; spot prices may be no worse at ensuring generation adequacy.¹⁵⁵

2. Reserves

Even apart from price caps, market mitigation, and lead times, regulatory intervention may still be necessary in a VOLL price-cap regime to ensure that LSEs have adequate operating reserves. During an overall shortage, LSEs have an incentive to free ride on other LSEs that have obtained adequate or more than adequate operating reserves, especially if ITPs do not control the circuit equipment needed to curtail deficient LSEs. To solve such a market failure, the ITP could require LSEs to satisfy a particular reserve margin. Since many factors, ranging from the type of generation in a region to transmission constraints,¹⁵⁶ determine the ideal level of operating reserves, permitting LSEs to choose their own level should prove more efficient than mandating a uniform reserve margin. Not surprisingly, market simulations under a variety of scenarios indicate that centralized determinations of operating reserves are often suboptimal compared to a competitive solution coupled with a small amount of demand response.¹⁵⁷

Still, to prevent deficient LSEs from free-riding on LSEs with adequate reserves, LSEs must be forced to internalize the costs of their behavior. In the case of an overall shortage, ITPs should order deficient LSEs to curtail their load. If the LSEs disobey the ITPs' directive, they would be fined the VOLL plus any transaction costs the LSEs' violation imposed on the system. Having to pay the VOLL plus the relevant transaction costs would force a deficient LSE to internalize the social costs of its conduct, and if the LSEs that had adequate reserves but nonetheless

¹⁵⁵ Under the RAR, an LSE may cure its resource deficiency two days ahead, a week ahead, a month ahead, or at any other point before the day-ahead spot market is run. Therefore short-term prices with respect to RAR do not include the day-ahead spot price or the ancillary-services price.

¹⁵⁶ Remedying Undue Discrimination, *supra* note 3, ¶¶ 489-90, 496.

¹⁵⁷ STAN HADLEY & ERIC HIRST, MAINTAINING GENERATION ADEQUACY IN A RESTRUCTURING U.S. ELECTRICITY INDUSTRY 48-49 (Oak Ridge Nat'l Lab. Paper, ORNL/CON-472, Oct. 1999). See also STOFT, *supra* note 7, at 182 n.2 ("Why should the cost-minimizing value of load shedding equal the time it takes the earth to rotate once times the number of digits on two hands divided by the time it takes the earth to orbit the sun?").

had to curtail were paid the VOLL, that should lead to the socially efficient result. An LSE that faces a fine equal to the social costs of failing to plan adequately will have the incentive to take into account every consideration relevant to setting its reserve margin, without being tempted to free-ride inefficiently on other LSEs' resources.

3. Better Than RAR, But Not First Best

Although a market with a VOLL price cap will yield a more efficient level of resource adequacy than a centralized decision-maker would produce, if some load is not paying RTPs and therefore cannot respond to price fluctuations, the resulting level of capacity will still not be first best.¹⁵⁸ Borenstein & Holland's market modeling demonstrates that increasing the proportion of load that pays RTPs will increase market efficiency.¹⁵⁹ But the optimal level of capacity could still be higher or lower than what such a market provides.

Whether capacity would expand or contract as more demand responds to RTPs depends on the relative elasticities of RTP demand at peak and off-peak points.¹⁶⁰ RTP demand is lower than flat-rate demand at peak prices and higher at off-peak prices, since RTP demand responds to changes in price. If RTP demand is sufficiently more elastic at peak points than at non-peak points, then capacity should contract as demand response increases: The increased demand at non-peak times will still be less than the capacity that was built to serve non-RTP peak demand. If RTP demand is not sufficiently more elastic at peak points compared to non-peak points, then capacity should expand:¹⁶¹ Increased demand at non-peak times will

158 SEVERIN BORENSTEIN & STEPHEN P. HOLLAND, INVESTMENT EFFICIENCY IN COMPETITIVE ELECTRICITY MARKETS WITH AND WITHOUT TIME-VARYING RETAIL PRICES (Ctr. for the Study of Energy Mkts., Univ. of Cal. Energy Inst., Working Paper No. 106, Nov. 2002). Note the difference between claiming that a price-spike market will not yield first-best capacity and claiming that it will not yield adequate capacity. All that is needed for a price-spike market to provide adequate capacity is "a very small fraction" of load that responds "to real-time prices." HADLEY & HIRST, *supra* note 157, at 49. See also STOFT, *supra* note 7, at 143 (concluding that reducing total demand as little as 2% in response to price spikes may be enough to produce a long-run market equilibrium). First-best capacity, in contrast, is what the market would choose if all load paid RTPs (i.e., if demand response were universal).

159 BORENSTEIN & HOLLAND, *supra* note 158, at 25.

160 *Id.*

161 This point can also be made in terms of different quantities of RTP load that share the same elasticity. Assume the RTP load level X decreases consumption at the peak price relative to lower prices but does not increase consumption at the non-peak price enough to exceed generation's level of capacity. At some point as RTP load increases beyond level X , the increase in consumption at the non-peak price exceeds available capacity, while consumption at the peak price does not. Generators decrease the peak price and raise the non-peak price. Depending on the relative magnitude of these changes, profits may increase and lead to an increase in generation capacity. *Id.* at 21-22, 30, fig.7.

RAR in FERC's Standard Market Design

more than offset the decrease at peak times and exceed the generation capacity previously available.¹⁶²

In the end, although a price-spike market may not result in first-best capacity, regulatory attempts to tweak capacity through subsidies (such as ICAP) or reserve margins perform even worse relative to the first-best level of capacity.¹⁶³ The result is more intuitive if capacity payments to generators are characterized as a “tax” on load and a capacity “subsidy” to generators. The constant “tax” that consumers pay throughout peak and non-peak periods distorts the effects of supply conditions¹⁶⁴ to which RTP demand should be responding. In other words, the distortions regulators create when attempting to solve distortions caused by flat-rate pricing leave load worse off overall when some of that load is paying RTPs.¹⁶⁵

Conclusion

The surest road to competitive electricity markets runs through demand response. Even if RAR accomplishes long-term resource adequacy, it will provide insufficient incentives for demand response and will perpetuate a price-cap regime that does the same. At worst, RAR will collapse under its internal contradictions and fail to provide long-term resource adequacy. FERC should replace RAR and the current price-cap regime with a price cap set at VOLL and a penalty equal to VOLL plus the transaction costs incurred for electricity that deficient LSEs take from the spot market during an overall shortage. Such reforms would permit the scarcity price signals needed to spur the development of demand response, a necessary condition for a viably competitive electricity market.

Update

After this Note went to press, FERC issued a White Paper that responds to comments on the SMD NOPR and that provides some indication of the final rule's content.¹⁶⁶ FERC seems to recognize that its claim to have jurisdiction to implement the original RAR is tenuous.¹⁶⁷ FERC envisions greater state discretion in developing a resource adequacy

162 Non-peak load may not increase enough to exceed generation capacity if the LSEs have a reserve margin, but it would at least begin to cut into the reserve margin.

163 *Id.* at 24-25.

164 *Id.* at 18.

165 *Id.* at 24.

166 FED. ENERGY REGULATORY COMM'N, WHITE PAPER: WHOLESALE POWER MARKET PLATFORM, FERC Docket No. RM01-12-000 (Apr. 28, 2003), available at http://www.ferc.gov/Electric/RTO/mrkt-strct-comments/discussion_paper.htm (last visited May 1, 2003).

167 *Id.* at 5.

program than its initial proposal allowed¹⁶⁸ and has retreated from its plans to set a minimum reserve margin.¹⁶⁹ Still, FERC is committed to every state's having some sort of resource adequacy program, and when states do not implement such a program, FERC would permit the appropriate ISO to do so.¹⁷⁰ Further, FERC proposes that the Regional State Advisory Committees ensure consistency among states' resource adequacy programs,¹⁷¹ a delegation of authority that may implicate the FPA's limits on FERC's jurisdiction. And even though FERC has repudiated a minimum reserve margin, FERC has not said what will happen to the RAR's other elements, including the enforcement mechanism and planning horizon. Regardless of the final rule's content, revamping the current price-cap regime along the lines outlined in this Note remains the optimal approach to reforming electricity markets.

168 *Id.*

169 *Id.* app. A, at 18.

170 *Id.* at 5.

171 *Id.* at 11.