Is Market Monitoring a Substitute for Regulation in Restructured Wholesale Electricity Markets? An Evaluation of the First Five Years

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Abstract

Over ten years ago, wholesale electricity markets in many parts of the U.S. were fundamentally restructured. Vertically integrated electric utilities were replaced by centrally designed and administered auctions repeated on a regular basis. Federal oversight was relaxed, as the Federal Energy Regulatory Commission relied (and continues to rely) largely on reports by "market monitors" regarding the competitive conditions in these new markets. A review of the monitors' reports during the first few years of this new approach reveals that fundamental concepts of economic theory, especially regarding the structure, conduct, and performance of markets, were either ignored or misapplied. As a result, markets were declared "competitive" despite clear evidence to the contrary. FERC's reliance on these monitors was misplaced.

I. Introduction

In the early 1990s FERC began to shift its implementation of wholesale power price regulation from cost-of-service to a greater reliance on market forces. The shift started with requirements that transmission owners open their capacity to other users on a non-discriminatory, average-cost basis, and then moved to the encouragement of Independent System Operators (ISO) and ultimately Regional Transmission Organizations (RTOs). The distinguishing characteristic of the latter is the operation of centralized auction markets into which sellers (and sometimes buyers) submit bids. The development of RTOs was a complement to state initiatives in California and the Northeast requiring the divestiture of generation assets by vertically-integrated electric utilities. Many wholesale entities now have the authority to charge market-based rates (MBRs), i.e., based on market conditions, rather than being limited to rates based average or "embedded" costs irrespective of market conditions. MBR authority is, under FERC's own standards, dependent on the existence of competitive markets and the absence of market power on the part of sellers or the mitigation of such market power as may exist.[1] If RTO markets are not competitive, then the shift to MBR may not be reasonable.[2]

The purpose of this paper is to evaluate the first years of market monitoring. The reason for this focus on a limited period of time is that precedents were set via FERC's

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[1] The continuing importance of this connection between MBR authority and market structure is highlighted by the docket opened by FERC in 2004 (RM04-7-000). See FERC (2004a). FERC has issued (at least) dozens of orders authorizing MBRs across the nation.

[2] This paper relies on publicly available information, both primary evidence in the form of reports by market monitors and secondary evidence in the form of research on market design and performance. It is possible the ISOs/RTOs examined here have conducted or are conducting additional analyses that address some of the concerns identified in this paper, but there is no way of knowing whether that is the case unless or until confidential investigative efforts are made public. One ironic casualty of divestiture and MBRs is the decreased availability of information on the cost structure of electricity suppliers. For example, see ISO New England 1999, p. 15).

acceptance of these monitoring reports and the Commission's preparation of evaluations of national restructured markets based on reports from individual monitors. FERC's Office of Market Oversight and Investigations referred to wholesale electricity markets as "competitive" as late as 2004 (see FERC 2005), without offering any evidence in support and despite the problems raised by market monitors and discussed here. Thus, the "primary sources" here are monitoring reports of the RTOs themselves from the late 1990s and early 2000s. We demonstrate that these initial monitoring reports were framed by an incomplete application of economic theory, and thus omitted consideration of several key indicators of industry structure, conduct and performance. In addition, various *ad hoc* metrics were devised that biased analyses, to the extent analysis was conducted, in favor of conclusions that restructured markets were either "competitive" or "workably competitive". The theory of workable competition itself was ignored, incompletely applied, or inappropriately applied. Very basic concepts about market structure and performance were not applied, yet conclusions were reached about the competitive nature of the restructured wholesale markets.

The theory of workable competition is based, at least in part, on a "pre-game-theory" paradigm of industrial organization, known as "structure/conduct/performance" (SCP). Although the SCP paradigm is itself an imperfect metric, and has been largely abandoned in favor of the intricacies of game theory, the older paradigm should not be discarded completely. The SCP paradigm can help identify potential problems at a level of complexity that is more accessible to policy-makers than the theory of N-person, infinitely-repeated, non-cooperative games. Game theory can and should then take over and help us understand market outcomes as well as design governmental policies (a.k.a., guardrails) to ensure that markets do not "run off the road". Although the focus here is on the beginning of the market monitoring effort, an epilogue looks briefly at the most recent studies by monitors, and demonstrates that some of the early problems persist, which supports the conclusion that the shortcomings of early monitoring efforts have persisted.

The general policy question is whether restructured wholesale markets overseen by monitors and FERC can deliver on the promise of competitive delivered prices to consumers, risk-adjusted returns to suppliers, and efficient production. The purpose of this paper is to consider one dimension of the question: what can we learn from observing the actions of the monitors themselves? Up to now, there has been no comprehensive review of the activities of the monitors, no systematic evaluation of the analyses conducted by the monitors, and no overall conclusions about whether existing approaches to market monitoring are sufficient to ensure societal welfare, both in the short run and the long run.

II. Market Monitors + Restructured Markets v. Traditional Regulation

Monitors are attached in various ways to FERC's preferred vehicle for the shift to markets: the Regional Transmission Organization (RTO).[3] RTOs are charged with, among other things, the design and operation of auction-based markets for wholesale power, including ancillary services, and congestion management systems that rely on a combination of locational marginal prices (LMPs) and financial transmission rights (FTRs) to protect (hedge) purchasers and sellers from the resulting uncertainty in spot

[3] These institutions are in a constant state of flux, some moving from "Independent System Operators" to "RTOs", depending on whether they have met FERC's criteria under Order 2000 for designation as RTOs.

market prices. In centralized markets, owners of generation resources typically submit bids into day-ahead and real-time markets, and RTOs accept, reject or modify ("mitigate") bids based on two objectives: cost and reliability. RTOs attempt to minimize the cost of the power purchased from the generators subject to physical transmission and generation constraints that limit the amount of electricity that can be delivered to specific points on the grid at specific times.

In order to ensure that RTO markets are sufficiently competitive, FERC relies heavily on "market monitors", which are employees of (or contractors to) the RTOs.[4] Market monitors have several functions: to observe the structure and performance of the markets operated by the RTOs; to report on the operation of such markets, both to FERC and more generally; to investigate reports of market manipulation; to assist in the development of new markets (e.g., the introduction of auctions for new products or changes in auction rules); to impose "mitigation" measures that limit prices under conditions determined not to be sufficiently competitive; and to impose sanctions or penalties on repeat offenders. Because of the presumption by FERC that these markets are workably competitive if overseen in this manner, the market monitors effectively bear the responsibility to assure competitive structure and behavior.[5] The particular approach

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[4] In some cases, monitors are also required as a condition of approval of a requested merger of privately-owned suppliers, even if an RTO does not operate the markets into which the merging entities operate.

[5] FERC has allowed generators to use market power mitigation programs overseen by RTOs as a "shield" if they are found to fail FERC's market power screens. See FERC, "Order on Rehearing", AEP Power Marketing, Inc., et al., Docket Nos. ER96-2495-018 et al., July 8, 2004, 108 FERC ¶61, 026: "An entity in an ISO/RTO that fails the screens, or wishes to go straight to mitigation, may point to ISO/RTO spot market mitigation as adequately mitigating market power." ¶179. See also "Order on Updated Market Power Analysis, Instituting Section 206 Proceeding and Establishing Refund Effective Date", Alliant Energy Corporate Services, Inc., Docket Nos. ER99-230-006 et al., December 20, 2004, 109 FERC ¶61,289, and "Order on Ancillary Services Filing and Providing Guidance", 119 FERC ¶61,311 at ¶43, Docket Nos. ER07-550-000 and ER07-550-001, imposing a market power analysis on the MISO Independent Market Monitor.

to "light-handed regulation" assumes that monitors are capable (legally and technically) of acting like regulatory agencies when necessary. With traditional rate-of-return regulation, state agencies walked a fine line between setting allowed rates-of-return at levels that were "too low", thus limiting the ability of investor-owned utilities to attract adequate capital, or "too high", thus reinforcing the inefficiencies of the Averch-Johnson effect in a particularly capital-intensive industry.[6] Similarly, monitors of designed markets walk a fine line between intervening "too much", thus potentially inhibiting entry of new suppliers and possibly undermining the financial viability of existing suppliers, and intervening "too little", thus allowing sellers (and other market participants) to raise prices to consumers above competitive or "just and reasonable" levels.

In these new markets, monitors play a role just as important as, if not more important than, the traditional roles played by state regulatory agencies.[7] At the same time, given the complexities of restructured markets, market monitoring is a much more difficult task in many ways than the traditional rate-of-return price regulation practiced by federal and state agencies. Traditional price regulation focuses on the reasonableness of the costs expected to be incurred to meet a monopolistic obligation to serve, including a rate of return to capital that is neither confiscatory nor overly generous. Overseeing restructured markets requires a much broader skill set, access to new and different forms of data and information, and ultimately much more sophisticated analyses and applications of economic theory.

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[6] For the seminal contribution, see Averch, H. and Johnson, L.L. "Behavior of the Firm Under Regulatory Constraint", *American Economic Review*, 52(5), December 1962, 1052-69.
[7] The opposite inference may be drawn from Stoft (2002), who devotes only seven pages to market monitoring in his otherwise lengthy treatise on market design for electricity.

Traditionally regulated monopolies operated in markets that were relatively static: a monopoly enterprise controlled all power supplies, transmission and distribution systems, and programs for demand-side response, conservation and energy efficiency. Centralized auction-based markets are much more dynamic: new products are introduced; new types of auctions for these products are designed, implemented, redesigned, and refined; entry and exit of new capacity (both generation and transmission), if they occur, mean that the definition of the "relevant markets" themselves (in an antitrust sense) are constantly changing; and ultimately, the borders between "reasonably or workably competitive" and "non-competitive" markets are also changing. These conditions require not only increased vigilance regarding market conditions, but also a constantly changing set of tools (analyses, market rules, mitigation programs, and sanctions) with which to respond to the changes in market conditions.[8] The result is not "free markets" in any sense of the phrase, but markets that are designed, overseen, implemented, and even regulated via the establishment of price caps.

III. Guidance for Market Monitors

Although market monitoring is of central importance to the Commission's approach to restructuring, the Commission initially set out only very general guidelines for the monitors, and then relied on FERC staff and the monitoring units of RTOs (and

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[8] For a confirmation of the complexity associated with protecting consumers under an MBR regime, see the presentation by FERC Chairman Pat Wood III, "FERC Policy Agenda", before the Energy Bar Association, Washington, D.C., November 4, 2004, available at www.ferc.gov/press-room/speeches.asp. The Chairman pointed to 11 different initiatives, efforts, and objectives intended to provide consumer protection.

recently, monitors hired by investor-owned utilities[9]) to develop the specific analyses that are relevant to the market structure and design of each set of RTO markets.

Order 2000 provides FERC's initial guidance in this area.[10] Because FERC recognized that the markets to be monitored had not yet been designed, detailed criteria or guidelines for monitors were not possible in late 1999. Thus, the Commission concluded only that RTOs should develop market monitoring plans.[11] Such plans should "ensure objective information", "evaluate the behavior of market participants", "assess whether behavior in other markets in the RTO's region affect RTO operations" and vice versa, and deliver reports on opportunities for efficiency improvements, design flaws, and market power abuses. More specifically, monitors should examine market structure, compliance with rules, behavior of market participants, and market power. Monitors were given the option only to report on potential abuses of market power, rather than recommending specific remedies. The Commission recognized that it had a responsibility under the Federal Power Act to ensure that markets were free of market power, but specifically pointed to the monitors as the "front line" for implementation of this responsibility.[12]

The Commission could have elected to be more direct and specific in its requirements, or could have relied on some simple economic concepts to provide more concrete guidance to monitors, both in terms of the kinds of information to be gathered

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[9] See FERC 2004b, for example.
[10] See 89 FERC ¶61,285, Docket No. RM99-2-000, December 20, 1999.
[11] Ibid., p. 462.
[12] Ibid., p. 464-5.

and the types of economic analyses performed.[13] In response, RTOs could have proposed alternative benchmarks or analyses that they considered more appropriate. In practice, monitors have tended to rely on the broad concept of "workably competitive markets", but without much attention to the details of this standard. "Perfect competition" in the textbook sense is not (and cannot be) generally used in studies of restructured wholesale power markets because the conditions of perfectly competitive markets are not and cannot be met, given the technology of electricity production and delivery. However, at least some of the characteristics of competitive markets could be used to evaluate market performance, focusing on short-run productive and allocative efficiency.[14] Workable competition has applied by the judicial system in reviewing the decisions of the Commission regarding market mitigation programs, and so its importance and relevance are increasing.[15] The theory of workable competition does not rely on the strict assumptions of perfect competitive, but instead sets out a list of practical criteria that

[13] This discussion sets aside the considerable controversy over whether market monitors have been sufficiently independent of the RTOs and the market participants. For a good example of the controversy on independence, see 120 FERC ¶61,254, "Order on Offer of Settlement and Complaints", September 20, 2007, in which FERC recognized "significant tension" (¶2) between the PJM monitor and the PJM board, and instituted settlement discussions to determine the details of a new governance structure.
[14] Productive efficiency refers to the achievement of the lowest cost of production for any hour; allocative efficiency refers to the achievement of spot prices that reflect the marginal cost of production and thus permit the use of electricity, relative to other inputs in production, in the most efficient manner.
[15] See U.S. Court of Appeals for the District of Columbia Circuit, Decision No. 03-1228, January 14, 2005, Edison Mission Energy, Inc. and Edison Mission Marketing & Trading, Inc. v. FERC. In this case, the Court endorsed "scarcity" as a justification for bids in markets that have been judged "workably competitive". As the PJM market monitor has pointed out, however, "scarcity pricing" can also be interpreted as the exercise of "just enough market power". See PJM Interconnection 2003b, p. 4.

should be applied. A succinct statement of these criteria is available in Scherer and Ross (1990, pp. 53-54).[16] These criteria are firmly embedded in the SCP paradigm.

"The number of traders should be at least as large as scale economies permit." This criterion allows the possibility of economies of scale, but otherwise points to the importance of an atomistic structure on both the supply and demand sides of the market. We should expect to see multiple owners of individual generating projects (unless there are economies of scale associated with multiple ownership) and opportunities for demand-side bidding by individual purchasers. We should also be examining the determinants of "minimum optimal scale": the smallest size of a producer at which a risk-adjusted competitive return can be earned.

"There should be no artificial inhibitions on mobility and entry." Realistically, barriers to entry in this industry exist and are largely beyond the control of FERC, in the form of capital requirements, transaction-specific investments, permits, licenses, and complex contracts. "Artificial barriers" may include processes for rent-seeking or rent-protecting behavior, or market rules that are unreasonably complex and inhibit entry by small competitors. As one example, environmental standards have allegedly been used by incumbents to block entry by potential competitors, thus preserving rents by a form of regulatory capture.

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[16] The criteria from Scherer and Ross have been edited to eliminate standards that do not obviously apply to bid-based wholesale commodity markets such as those operated by RTOs. That is, this paper *weakens* the standards of workable competition, by setting aside criteria regarding quality differentials, exclusionary and coercive tactics, sales promotion, price discrimination, product quality, advertising, and responsiveness to end-use consumer preferences. Aside from these eliminations, Scherer and Ross' criteria are replicated exactly here as quotes. The discussion following each bullet is mine, not Scherer and Ross'. See also Peters (1990).

"Some uncertainty should exist in the minds of rivals as to whether price initiatives will be followed. Firms should strive to attain their goals independently, without collusion." Structural conditions may facilitate price collusion, either explicit or tacit. For example, if the number of suppliers is small enough, or if suppliers interact in infinitely repeated games, the opportunities for collusive interactions increase because suppliers can set bids based on expected reactions of the other suppliers, and then redesign strategies based on actual reactions.

"Inefficient suppliers and customers should not be shielded permanently." More efficient suppliers should have the ability to enter the market, compete against incumbents, and force down prices. Regulatory decisions that ensure returns to investments of relatively inefficient suppliers would not meet this standard. Ensuring returns is, ironically, one of the objectives of tradition, rate-of-return regulation.

"Firms' production operations should be efficient and not wasteful of resources." Efficiency can be measured in a number of ways, but here refers mainly to decisions to use inputs efficiently (i.e., minimizing the cost of production by selecting the right combination of inputs) in the short-run, as well as adopting new technologies as they become available to minimize costs over the long-run. This is similar to another criterion: *"[o]pportunities for introducing technically superior new products and processes should be exploited."*

"Output levels should be responsive to consumer demands." This criterion requires some elasticity on both the demand and supply sides of the market. If demand elasticity is low (or even zero), then changes in prices will not lead to changes in consumption, which in turn will not lead to changes in production, either in total or as

distributed across suppliers. If supply elasticity is low, then suppliers will not be able to adjust output as the demand for the product changes. Although the time frame is not specified by Scherer and Ross, one could look at both short-run and long-run elasticities of supply and demand.

"Profits should be at levels just sufficient to reward investment, efficiency, and innovation." Investors should earn returns over the long run that are only competitive, adjusted for the risks of production and sale in well-designated markets. If investors earn returns in excess of risk-adjusted levels, then prices are presumably higher than the "just and reasonable" standard of the Federal Power Act; if returns are less than the competitive levels, insufficient supplies will be forthcoming and one would expect to see non-price rationing.

"Prices should encourage rational choice, guide markets toward equilibrium, and not intensify cyclical instability." In the short run, this points to the importance of spot prices being close to marginal cost, so that consumers will use the "right" amount of the product relative to substitutes in the short-run. However, these RTOs trade in several products, which are not perfect (or even imperfect) substitutes. This points to the need for an analysis of the competitive state of several different "markets", properly defined.

These criteria are not, as Scherer and Ross conceded, easy to apply. However, as we shall see, the standards of workable competition are in fact referenced by the market monitors studied here, by FERC, and by the judicial system. If the theory of workable competition is going to be a substitute for other regulatory actions or interventions, it is important that the theory be applied in a manner that all market participants can trust and rely upon. One major question facing FERC is whether the Commission can rely on the existing RTO monitoring programs to demonstrate workable competition and thus justify the light-handed regulation demonstrated in decisions to award MBR authority.

IV. PJM: "Optimal Market Power"

Although the PJM markets have been described as "reasonably competitive", "workably competitive", and "competitive" throughout various reports reviewed here, a more accurate description of PJM's markets during this period would be highly regulated and subject to market power. This is briefly demonstrated by a declaration filed at FERC in September 2003[17] and a review of certain portions of the 2004 PJM Operating Agreement.[18] In fact, PJM has over the years operated a complex set of markets that combine cost-based and market-based rates. Unconstrained auctions have been complemented by overall bid caps, reliability must-run (RMR) contracts and unit-specific cost-based bid caps. Even the LMP system has limited bids in transmission-constrained areas such that markups over marginal cost not exceed ten percent, which is a form of cost-based bid regulation. One novel objective of PJM's market evaluation has incorporated the concept of the "optimal amount of market power". "Scarcity pricing can be implemented by letting existing generators exercise market power without any rules or by letting generators exercise just the right amount of market power." (PJM Interconnection 2003b, p. 4.) Furthermore, "[i]n effect, this approach is an attempt to

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[17] The purpose of this affidavit (Bowring 2003) is apparently local market power. Source: www.pjm.com.
[18] See the AMENDED AND RESTATED OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C., PJM Interconnection, L.L.C., Third Revised Rate Schedule FERC No. 24, which includes all revisions approved by FERC in orders issued through June 28, 2004, available at www.pjm.com. Schedule 1 sets the rules for market operations, including establishment of locational marginal prices and compensation to generation units determined to be required for reliability reasons (so-called "RMR" units). Cost components used to compensate the latter are listed in Schedule 2.

apply the [traditional regulated] rate-of-return approach. Regulation attempted to solve exactly this problem but was equipped with a much more detailed regulatory apparatus for setting and monitoring the resultant prices." (Ibid., p. 5) Despite FERC's public statements, PJM markets were actually regulated with the objective of achieving "optimal market power", even though this is not a well-defined or widely used concept in the industry or the discipline.

The market monitor's report for 1999 contained an extensive discussion of the potential for the exercise of market power, focusing on the "boundary conditions" that occur during high demand periods. Under PJM's rules, generators with portfolios consisting of a variety of resources had a greater opportunity to exercise market power on high demand days, because they could offer one small unit at a very high marginal price, weighing the risk that the unit would not be dispatched against the potential profits if the unit actually sets the market-clearing price for <u>all</u> of the seller's (and others') units. Thus, generators with large and diverse portfolios generally have more incentive as well as opportunity to exercise market power. Also, generators who are "long" in the market relative to their obligation to serve will be interested in using their market power, if any, to raise spot market prices. In fact, PJM's analysis of high demand periods indicated that the concentrated ownership of small units led to extremely high market-clearing prices, and on June 10, 1999 prices were set far above the marginal cost of the marginal operating units (PJM Interconnection 2000, p. 24-26).

Temporarily high prices such as those experienced in 1999 could be explained by, among other things, "scarcity" and "market power".[19] "Scarcity" was defined as a situation in which the demand curve lies to the right of the supply curve: there is no market-defined price, and thus there can be no <u>competitively</u> determined price. (See PJM Interconnection 2000, p. 28.[20]) If there is no competitive benchmark, prices based on bids that are greater than the marginal cost of the most expensive unit operating inside PJM cannot be judged to be competitive prices, or a reflection of workably competitive markets. In situations defined by scarcity, as defined by PJM, sellers have the ability to set a "scarcity price" at any level without risking a loss of sales; normally this implies some fundamental imperfection in the market. Thus, there was no practical distinction in PJM at this time between the exercise of market power and scarcity pricing.[21] In 2002, market power was defined as a situation in which "a significant block of MW offered their energy at prices exceeding marginal cost and exceeding the price of available imports."[22] As noted earlier, "scarcity" was defined as situations in which the demand curve lies to the right of the supply curve, whereas "market power" was redefined in 2002 as situations in which the supply (marginal cost) curve has been shifted up by the bidding behavior of sellers, but still intersects the demand curve to establish a market-clearing

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[19] The importance of this distinction for public policy generally is reinforced by the decision in 2005 of the D.C. Circuit Court regarding the NY ISO, which at least admitted a concern about the exercise of market power, as opposed to "true scarcity". However, the Court's allowance of "scarcity pricing" runs headlong into the distinction offered by the PJM monitor, who defined scarcity as the lack of <u>any</u> market price. Notwithstanding the Court's reasoning, without the existence of <u>any</u> market price as a benchmark, it is not possible to determine if the actual prices were reasonable or not. See *Edison Mission Energy, Inc. and Edison Mission Marketing and Trading, Inc. v. FERC*, No. 03-1228, decided January 14, 2005.

[20] In later reports, the MMU made the distinction between "scarcity", where the demand and supply curves do not intersect, and "market power", where bidders raise the supply curve above marginal cost but the demand and supply curves can still be said to intersect.

[21] In its report on 2001, the MMU did differentiate between "scarcity" and "market power" (PJM Interconnection 2002, p. 29): "[p]rices reflected economic scarcity because loads exceeded the energy available from units operating within PJM at prices equal to marginal costs."

[22] Ibid.

price. Although this distinction may be clear theoretically, it points to two fundamental weaknesses in PJM markets at this time: lack of adequate supply at any price and the ability of sellers to manipulate the bid curve.

On one day in 1999 over 2,000 MW (3.6 percent) of capacity that should have been available was not, and its absence could not be explained (PJM Interconnection 2000, p. 50). The analysis of potential market power in this situation suggested that the combination of a fixed obligation to meet capacity requirements (i.e., a fixed demand) combined with the paucity of owners of excess capacity (i.e., concentration on the supply side) created the conditions under which market power could be exercised (PJM Interconnection 2000, p. 51). Further, the combination of a *pro forma* charge for not meeting one's capacity obligation and weak oversight of capacity obligations led to incentives to undersupply capacity (PJM Interconnection 2000, p. 53). Nonetheless, PJM concluded that the capacity markets operated "effectively" (PJM Interconnection 2000, p. 52): in a manner that would not threaten reliability (PJM Interconnection 2000, p. 55).

One critical element of any market analysis is the ability of suppliers to charge more than competitive market conditions would permit over the long run. On that subject, the MMU concluded (PJM Interconnection 2001b, p. 4; see also p. 14):

> [i]n 2000, the net revenues from the energy market, the capacity market, ancillary services and operating reserves would have covered the fixed costs of peaking units with operating costs of about $45/MWh which ran during all profitable hours. The operating cost of $45/MWh is at the low end of operating cost estimates based on the average cost of gas in 2000 and the heat rate for a peaking unit. The market results in 2000 suggest that the fixed costs of marginal capacity were almost but probably not fully covered by net revenues, given that the estimate of net revenues is an upper bound and that the fixed cost estimate may be somewhat low. Recognizing that market results will vary from year to year, the results in 2000 are consistent with the expected operation of a competitive market. The data do not suggest that generators' net revenues exceeded the fixed costs of

> generation and thus are consistent with a finding that there was no systematic exercise of market power in PJM during 2000.

The conclusion was clearly much stronger than the evidence. The calculations suggested that marginal generation units may have not recovered all their fixed costs, but this implies that inframarginal units may have received more than a competitive return on their investments. PJM offered no evidence of net revenues for such inframarginal units. It is also important to recognize that PJM's *pro forma* analysis showed that new generators' expectations regarding future profitability shifted dramatically over time. In 1999, the *pro forma* analysis would have encouraged entry, whereas in 2000 it would have deterred entry. These are not the kinds of conditions that can be counted on over time to ensure either an adequate supply of electricity or competitive prices.

The markups of price over marginal costs in 1999 and 2000 demonstrate that PJM should have been concerned at the time about the competitive state of the markets.[23] PJM reported an average annual markup of two percent in 1999, with a maximum markup of eight percent in July (PJM Interconnection 2001b, p. 16). However, the average markup doubled in 2000, and the maximum markup shifted to 12 percent in December. Price-cost margins were clearly increasing, which should have raised concerns about the competitive state of the market generally.

The MMU argued that the method used to estimate markups overstated the "system markup" over the competitive price because "the marginal unit had, on average, lower marginal costs than did other operating units" (PJM Interconnection 2001b, p. 20). This observation should have set off warning signs, because "the rank order of units by

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[23] Spot market prices may exceed marginal costs at the same time that total revenues fall below total costs, especially on a *pro forma* basis for specific marginal units.

price offer differs from the rank order of units by cost offer." (PJM Interconnection 2001b, p. 20) That is, the highest bids were not offered by units with the highest marginal costs. This implies strategic behavior on the part of bidders, which should have been a source for concern, rather than an explanation for an alleged overestimate of the markup of prices over their competitive levels.[24]

In general, the ability of monitors to calculate competitive benchmarks has been undermined by the decline in the availability of data on fuel costs. For example, prior to the introduction of markets in 1999, PJM collected a broad variety of information on the costs of all generating units in the PJM control area because it operated a tight power pool. By the time of the monitor's report on 2000, the MMU noted that non-regulated generators were not required to submit data on FERC Form 423 (*Monthly Report of Cost and Quality of Fuels for Electric Plants*), and so it was not possible to conduct the same kind of marginal cost calculations that had been done in 1999 (PJM Interconnection 2001b, p. 36). It took until 2003 for the MMU to call for mandatory reporting of fuel cost data. (See also Moody (2004).) Lack of information suggests that a serious concern should have been expressed just about the ability to judge market conditions.

Another market examined by the MMU in 2000 was the auction for FTRs (a form of hedge against the risk of transmission congestion), which the MMU declared "competitive" (PJM Interconnection 2001b, p. 83). Although liquidity in this market had increased since 1999, there were no analyses of structure, conduct, or performance. More important, the variation of total FTR revenues across different "sinks" (nodes on the

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[24] "Strategic behavior" refers to the the ability of sellers to bid above marginal cost in an effort to manipulate prices and earn more-than-competitive returns. An alternative explanation of this phenomenon would be that bidders were just guessing and offering prices that might have been rejected. However, "just guessing" does not sound like a characteristic of workable competition.

transmission system dominated by loads, rather than generation) suggests that the markets in the PJM Interconnection were actually separating (PJM Interconnection 2001b, Figures 5-8, pp. 89-92). This concern is reinforced by data for 2000 (PJM Interconnection 2001b, p. 93) showing that the number of buses with changes in congestion hours greater than 100/year "experienced significant increases in congestion-event hours between 1999 and 2000." The MMU did note (PJM Interconnection 2001b, p. 97) that "[t]he rules governing the submission of increment offers and decrement bids in the day-ahead market permitted market participants to create congestion in the day-ahead market on paths where they held FTRs, without incurring financial risk, in order to make their FTRs more valuable." This incentive required a rule change that eventually forced FTR holders to disgorge any profits they made due to the creation of congestion in the day-ahead (DA) market that was inconsistent with actual congestion in real-time (PJM Interconnection 2001b, pp. 97-98). However, before the rule change, it would have been more accurate to conclude that the markets were subject to manipulation, not that they were reasonably competitive. Again, the facts conflicted with the conclusions.

Concentration of ownership of the marginal generating units across PJM remained a problem in 2001. (PJM Interconnection 2002, Figure 8, p. 24.) For example, two companies each owned 15-20 percent of the "marginal units" (generating units that were on the margin for one or more five-minute intervals during the year), while two other companies each owned ten to 15 percent of the marginal units.[25] Further,

> two companies owned the marginal unit in more than 30 percent of the five minute intervals in 2001, while four companies owned the marginal unit in about 60 percent of the intervals in 2001, and eight companies owned the marginal unit

[25] The fact that this analysis pertained to PJM as a whole should have been a cause for even greater concern, because the concentration of ownership of generation in load pockets was probably much higher.

> in almost 90 percent of the intervals. Such concentration of ownership facilitates collusion. In 2000, almost 80% of the marginal units were owned by the top five companies while in 1999, more than 60% of the marginal units were owned by the top five companies. (PJM Interconnection 2002, p. 23)

Although these are different ways of measuring concentration, PJM's markets were apparently becoming more, not less, concentrated over time, especially on the margin, where it would be most difficult to rely simply on market forces to protect consumers.[26]

In January 2001, PJM discovered that market participants had found a way to exercise market power in the daily capacity credit markets. In these markets, LSEs who were "short" on their capacity obligations purchased capacity credits. The revenues from such purchases were allocated solely to those who held unsold capacity resources. Entities with uncommitted capacity could offer it for sale at a posted price and guarantee that they would receive a share of the revenues from those LSEs who were short on capacity. As a result, capacity was withheld from the market by one seller who was "long" more than the entire size of the daily capacity market, causing the price to jump dramatically, with the entire revenues from capacity deficiency payments allocated to that single seller (PJM Interconnection 2002, pp. 81, 86-7 and 90). As the MMU concluded (PJM Interconnection 2002, p. 91),

> [t]he capacity credit market rules did not expressly prohibit the actions of Entity1, which took the form of economic withholding. Entity1 successfully withheld capacity by offering it at prices higher than the CDR [capacity deficiency rate] because it held capacity that LSEs needed to purchase to meet their capacity obligations. Entity1 held more net capacity than the total excess capacity in the market.[27]

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[26] This also demonstrates the lack of longitudinally consistent metrics that would facilitate analyses of changes over time.

[27] "Entity1" was the name that PJM gave to the specific market supplier in its public reports, due to policies masking the identities of suppliers who were found to have violated market rules or otherwise took actions that led to investigations.

As a result, PJM changed the rules for distribution of the revenues from the daily capacity market to discourage withholding (PJM Interconnection 2002, pp. 69 and 92). Again, a conclusion that this market was competitive would have been inaccurate at best.

Some reported statistics for 2002 suggested that markets were becoming less competitive. For example, the number of congested areas increased in 2002 from 2001, implying more fragmentation of markets, and the estimated mark-up was at or above ten percent over bids in all months (PJM Interconnection 2003a, Figure 2-5, p. 28). Another rule change was necessary in July 2002 because contract-path, scheduled flows did not match actual flows into PJM from adjacent control areas. This mismatch took advantage of price differentials within PJM based on the ability to schedule across different interconnection points outside PJM (PJM Interconnection 2003a, pp. 56ff.). In one case, a market participant scheduled power to one interchange point in order to receive the LMP at that point, whereas the power actually flowed through a different interchange point. In another, the market participant scheduled power out of PJM, through an adjacent control area, and back into PJM, again to take advantage of differences in LMPs. A rule change eliminated the incentive to "game" the system by scheduling power to maximize payments by PJM for imports in ways that were inconsistent with the actual power flows. The discovery of "gaming" suggests non-competitive behavior.

In addition to the annual state of the market reports, the PJM MMU also responded to specific requests for studies of particular problems. The 2001 special report on enforcement noted that there had been three incidents that had led to changes in rules because of the need to mitigate the exercise of market power.

- First, generators had submitted arbitrary operating constraints (e.g., minimum run times) in order to evade the $1,000/MWH price cap (PJM Interconnection 2001a,

p. 5): "MMU investigations determined that this design flaw resulted in purchasers of electricity during the summer of 1999 paying substantially in excess of the amount that they would have paid but for this practice." By stating that a specific generating unit had to be run for, say, a minimum of six hours when it could be run for only four hours meant that a more expensive but more flexible unit, perhaps belonging to the same seller, would be dispatched instead. The more expensive unit would then set the market-clearing price for all generators, including the one with the excessively high minimum run time, if it ran during the hours with higher than necessary prices. A change in the method for determining payments to generators was needed to correct this problem.

- Second, the MMU investigated a complaint that a transmission owner had used advance knowledge of a transmission outage to take an advantageous position in PJM's FTR auction. This led to a requirement that planned outages be noticed before the FTR auction for the month of the outage; absent such notice, PJM could require the planned transmission outage to be scheduled so as to minimize congestion costs.[28]

- Third, the MMU discovered that market participants could purchase FTRs and then use DA virtual schedules (known as "increment" and "decrement" bids in the PJM markets) to create congestion that would increase the value of their FTRs. The solution in this case was another rule change, which required the disgorgement of any profits associated with virtual schedules that created day-ahead congestion inconsistent with real-time congestion. Finally, the MMU noted that its ability to respond to market conditions was hampered by the need to get FERC approval, and requested additional enforcement tools.

This litany of problems, leading to several rule changes, belied the MMU's broad and repeated conclusions that markets in PJM were "competitive". In fact, it pointed to the opposite conclusion. Furthermore, few of the usual metrics for evaluating the competitive state of the market were applied, in part due to a lack of required data.

[28] PJM Interconnection 2001a, p. 6.

V. New York: Withholding, Counterintuitive Flows and Strategic Behavior

Unlike PJM, which has introduced markets for specific products gradually over time, New York chose the "big bang" approach.[29] In late 1999, the ISO "simultaneously implemented competitive day-ahead and hourly energy markets, operating reserves markets (30-minute, 10-minute spinning, and 10-minute non-synchronous reserves), a regulation market, an installed capability market, and a TCC market." (See Patton, 2001b, p. i.) In the subsequent four years, New York's external market advisor issued four annual reports (2000-2003), plus a variety of specific affidavits and review of individual subjects.[30] The first annual report (Patton 2001b) concluded (p. iii) that "[t]he electric markets in New York have been competitive under most conditions experienced to date." The report also concluded that various analyses of long-term trends yielded the conclusion that the NY-ISO's markets have generally been "workably competitive", despite clearly identified barriers to entry of new generation and transmission capacity. (Patton 2001b, p. vii.)

Unfortunately, the conclusions of the New York monitor was at odds with the details in the reports. One early flaw was the introduction of several sources of bias into estimates of withholding behavior. "Withholding" is an action that removes supply from a market, with the objective of increasing profits on remaining sales. "Economic withholding" was defined as bids in excess of thresholds tied to individual units' bids during recent periods defined as "competitive". Such bids were treated as "excess capacity", calculated separately for the day-ahead and real-time markets. Large amounts

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[29] This should not be confused with the California market experiment, which led to very different results.
[30] The scope of work for the contracts between the ISO and the external monitor is not a matter of public record, so it is not possible to determine how much latitude the external monitor had in preparing its analysis, either in terms of data or methodologies.

of excess capacity could indicate economic withholding. However, excess capacity was "reduce[d] . . . to account for bids at prices greater than $500 [per MWh]" (Patton 2001b, p. 8). That is, quantities associated with bids over $500/MWh were eliminated from the calculation of excess capacity. The justification offered for such a reduction was that the amount bid over $500 could vary significantly from day to day. The effect of this adjustment was to reduce the amount of excess capacity at any given price, and thus make it appear that suppliers were not withholding capacity from the market.[31] By reducing excess capacity at any given price, the monitor was able to reach the conclusion that economic withholding was not a problem. However, this approach was biased in favor of the conclusion that markets were not subject to withholding behavior.

In order to determine whether the bidding behavior itself was competitive (Patton 2001b, p. 55), the external monitor examined "whether the total hourly quantity of bids exceeding the physical or economic withholding thresholds increases as the market load increases." The withholding thresholds were set by the ISO at the lesser of $100/MWh or 300 percent above the reference price, which was in turn determined on a unit-specific basis during periods when the market conditions were deemed "competitive". Assuming, for example, that the reference price was at least $33/MWh, this would allow bids $99/MWh above competitive levels to be submitted and <u>not</u> trigger the label of economic withholding. Although these thresholds were set by the ISO itself, including them in the analysis of bidding behavior the external monitor created a bias: bidding behavior that

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[31] Also, this calculation was reported only for Hour 14. See Patton (2001b), Figure 5. The report explains (p. 9) that this limitation "eliminate[d] any potential pricing disparities due to peak/off-peak differences (e.g., start-up hours or high-ramp hours)." The logic of this is unclear. A more complete analysis would simply have looked at all hours, and attempted to distinguish patterns of excess capacity, appropriately calculated, across different market conditions.

was not competitive but did not cross the threshold was excluded from the analysis. Without knowing how many bids were submitted that were, for example, just shy of the threshold, it is not possible to conclude whether bidding behavior was competitive or not.

One continuing debate at the ISO was whether the reference prices were "too generous" to the sellers by permitting energy bids up to the lesser of $100/MWh or 300 percent higher than reference ("competitive") price levels. To address this, the external monitor tested for the sensitivity of prices to lower thresholds (Patton 2001b, pp. 63ff.).[32] For one very small sample (four days!), a test of a lower threshold ($50/MWh or 100 percent higher than the reference price) led to the conclusion that lower thresholds would not have triggered a charge of economic withholding. However, during these four days, the bids were actually <u>significantly higher</u> than the reference prices, which suggests that suppliers were earning super-competitive returns, at least compared with marginal cost.[33] Because of the small amount of capacity in the sample, the external monitor concluded that "the conduct identified had no substantive effect on prices" (Patton 2001b, p. 64). In this case, extrapolation from a sample of four days was an extremely weak approach.

Reports on markets in NY did implement some standard economic analyses, for example checks on the effects of arbitrage on price differentials. However, arbitrage between the NY-ISO markets and adjacent markets in New England and PJM showed considerable amounts of apparently counterintuitive behavior (Patton 2001b, Figure 23, p. 41). In this context, "counterintuitive" power consistently flowed *from* high-cost *to* low-cost areas: e.g., exports to PJM when the western New York price was higher than

[32] Note that the external monitor used the economic withholding thresholds in the excess capacity analysis without conducting such a sensitivity test.
[33] The choice of these four days may itself have been biased. We are not informed of the selection criteria.

the PJM price, and imports when the western New York price was lower than the PJM price. Although more than 40 percent of the hour-ahead interchange observations were counterintuitive, the external monitor concluded that the results were "reasonably efficient" (Patton 2001b, p. 42), arguing complexity of the rules, mismatches between market rules in PJM and New York, lack of perfect knowledge, and aversion to the risks associated with relatively small differences in prices, which could turn an hour-ahead asset into a real-time liability. However, the conclusion regarding "reasonably efficient" was not based on any direct evidence, nor was "reasonably efficient" itself defined.

The overall efficiency of the market depends on the degree to which the combined PJM and western New York dispatch was more expensive than it needed to be because of these counterintuitive flows. The external monitor presented no evidence on the total cost of dispatch associated with the counterintuitive flows, either absolutely or relative to the size of the combined PJM/NY hour-ahead market. The importance of this issue was emphasized by the subsequent observation that over <u>fifty</u> percent of the hour-ahead flows between NY and New England were <u>also</u> counterintuitive (Patton 2001b, p. 43). Something was not working correctly on the borders (or "seams") between the New York markets and adjacent markets. The fact that these exports were scheduled (i.e., intentional) may be explained by the factors noted by the external monitor, but could also be explained by strategic behavior on the part of suppliers: if the profits earned in NY by exporters from eastern New York to New England exceeded the losses associated with exporting the power to New England, and if the exports actually contributed to the inflated prices in New York (which is actually confirmed by the report [Patton 2001b, p. 45]), then the seemingly "counterintuitive" behavior may have demonstrated perfectly rational profit-maximizing behavior by sellers in a position to manipulate prices via "export withholding".[34]

In addition to these problems, the external monitor's evaluation of ancillary service markets revealed a significant exercise of market power in the market for ten-minute non-synchronous reserves (NSRs; Patton 2001b, pp. 72ff.). This market was highly concentrated, and the sellers (of which there were two, effectively) managed to extract $70 million in excess profits in less than three months.[35] The ISO changed the relevant rules but was not authorized to force the excess profits to be disgorged. After the rule change, the excess supply of 30-minute reserves apparently kept these prices down. Finally, the market for regulation was plagued by low amounts offered relative to the capability of generating units to supply this service. This resulted in prices that were relatively high during the first part of the year. It would appear that economic withholding was a strong factor in keeping prices high through the spring (Patton 2001b, Figure 45, p. 85), and yet market operations were declared workably competitive.

In the discussion of withholding for 2001, the external monitor introduced – though did not actually use – the supply function equilibrium (SFE) approach of Klemperer and Meyer (Patton and Wander 2002, p. 18). The SFE model yields an estimate of the optimal amount of withholding, based on some fairly strict assumptions about the structure of the market.[36] SFE requires the estimation of variables such as: (1)

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[34] In addition, the software corrections introduced by the NY-ISO in the fall of 2000 did not eliminate the problem of seemingly counterintuitive flows (Patton 2001b, pp. 46-47), thus lending support to the hypothesis that the computer models were not at fault.

[35] This had a similar deleterious effect on prices in the ten-minute spinning reserve market as well (see Figure 41, p. 77). It is not clear whether the estimate of $70 million in excess profits includes both these markets.

[36] See Klemperer and Meyer 1989, Green 1996, and Green and Newberry 1992.

the output under competitive conditions, (2) the price (for any given hour), (3) each generating unit's marginal cost curve (to be able to locate the marginal cost at the optimal level of withholding), and (4) the sensitivity of price to changes in the quantity supplied.[37] Estimates of these variables can be used to evaluate the potential for optimal withholding behavior. Price is a known quantity from the historical records; competitive output should be determined by the marginal cost of production at the known price; the marginal cost curve itself should be available for each thermal unit due to the prior operation of the New York markets as a tight power pool; and the slope of the supply curve should be available from the aggregation of all units' marginal cost curves. This was at least a step in the right direction, theoretically.

However, although the SFE approach was discussed, the external advisor did not actually apply it. As noted above, all of the information necessary to apply the SFE approach should have been available from the ISO, so it is not clear why the theory was not applied. After stating that the competitive output should be directly correlated with the size of the seller (Patton and Wander 2002, p. 19),[38] the external monitor returned to the same approach to withholding applied in its report on 2000, with all of the same weaknesses, although a visual inspection of the results suggests that the negative relationship between load and withholding may have been stronger in 2001 than in 2000

[37] See Appendix C in Patton and Wander 2002.

[38] This assumption is clearly unfounded. Competitive output is a function of marginal cost, which is in turn determined mainly by heat rates and fuel prices in thermally based power systems. The size of the firm owning the individual units plays no obvious role in the determination of competitive output. In fact, in a perfectly competitive market, all firms are the same size, so there could be no variation in competitive output as a function of the size of the firm. This statement contradicts basic economic theory or is an admission that markets in New York were not competitive.

(compare Figures 14-15 in Patton and Wander 2002 against Figures 30-31 in Patton 2001b).[39]

An important innovation in New York was the ability of entities to participate in markets purely as speculators, and sometimes speculation can improve efficiency. See Saravia (2003). In the energy markets at hand, buyers and sellers are allowed to bid on a "day-ahead" basis and in "real-time". "Day-ahead" means offers to buy or sell that are submitted on, say, Wednesday, for deliveries of power on Thursday. Bids are allowed to be submitted by "real suppliers" and "real buyers", who intend to actually generate energy and use energy, but bids are also allowed to be submitted by entities that have no intent to make or take physical delivery. The latter are called "virtual bids" because they never close (deliver) in physical terms. For example, if a market participant submits a virtual bid to sell electricity at $50/MWh on a day-ahead basis, it is betting that the real-time price will be, say, $40/MWh, and it will be able to purchase "real" energy in real-time and resell it to make a $10 profit. Conversely, an entity might virtually bid to buy electricity at $50/MWh, hoping that the real-time price is $60, in which case it can sell the purchase obligation to someone else for $60 and again make a $10 profit. These are basic forms of arbitrage across time that should help markets work more efficiently because different buyers and sellers will generally have different expectations about the differences between day-ahead and real-time prices. Virtual bidding should drive down the price differential between day-ahead and real-time markets.

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[39] The 2002 withholding analysis followed the pattern established in earlier years: physical and economic withholding were both estimated using the same approaches, but "export withholding" was ignored. Export withholding is clearly a potential problem if market participants can take advantage of price differences between borderline nodes that connect the RTO to a single adjacent control area, as we saw with PJM. This technique was repeated in the report for 2003 (Potomac 2004).

However, virtual bidding can be used strategically *either* to arbitrage away price differentials *or* to try to influence real-time prices in a non-competitive manner. The external monitor theorized in 2002 that the latter strategy would be accomplished by submitting virtual bids that were "price-insensitive". A "price-sensitive day-ahead virtual bid" was defined as one closely related to the expected real-time price at the same node for the same hour. In contrast, a "price-insensitive day-ahead virtual bid" was defined as unrelated to the bidder's expectations about the real-time price at the node/hour. The strategy behind such price-insensitive bids (Patton and Wander 2002, p. 27) "could include making a large virtual load purchase in a constrained zone in order to cause congestion in the day-ahead market that would benefit the owner's TCCs [transmission congestion contracts] or other generating assets." That is, the virtual bid might be used to gain an economic advantage for an asset held by the bidder.

The methodology employed for the analysis of virtual bidding was unique but puzzling. First, "price-insensitivity" was defined as virtual load bids greater than \$100/MWH and virtual supply bids less than \$5/MWH (Patton and Wander 2002, p. 27). Not surprisingly, it turns out that very few virtual bids fell into the "insensitive" category (Patton and Wander 2002, Figure 19, p. 28). However, the problem seems to have been defined away, quite literally, by the definition of "price-insensitive". By using only the tails of the price distributions (on the demand and supply sides) to define "price-insensitive bids", the analysis was a self-fulfilling prophecy. Given the premise, which is reasonable and plausible, that virtual bids might be used to gain an advantage for another asset of the bidder, it would have been more straightforward to look at the behavior of specific bidders under constrained circumstances (i.e., specific paths on specific hours), when the system was under stress and thus susceptible to anti-competitive behavior by market participants. However, such an investigation was not conducted, or at least not reported.

Virtual trading continued to expand in New York, especially after May 2002, suggesting that arbitrage should have narrowed price differences between day-ahead and real-time (Potomac Economics 2003, p. 29ff.). However, in the first full year of operation, virtual bidding revealed an interesting pattern in the New York City/Long Island area: the amount (MWh) of virtual load bids exceeded the amount of virtual supply bids in all months by significant amounts (see Potomac Economics 2003, Figure 20, p. 29). On balance, virtual bidders were consistently counting on real-time prices to exceed day-ahead levels. In a mature market, one would expect that arbitrage opportunities would be discovered and used to eliminate price differences over time, but with the expectations of market participants adjusting accordingly. The lack of convergence combined with persistent bidding patterns implied some type of market imperfection. In general (see Figure 7, Potomac Economics 2003, p. 9), the report showed that prices in NYC, which were typically found in load pockets, were lower, not higher, in real-time than at day-ahead (with the exception of the Astoria East load pocket). However, the persistent excess of virtual load bids over virtual supply bids indicates that the expectations of market participants were exactly the opposite. No explanations were offered for this apparent contradiction.

During 2002, there were actually two kinds of systematic bias in the patterns of virtual trading: the amount of virtual energy purchases bid into New York City was always greater than the amount of virtual energy sales bid into New York City, sometimes by an order of magnitude. This suggests that the bulk of the energy that was bid but not intended to make or take physical delivery of power systematically expected energy prices to rise in real-time during 2002, compared with day-ahead, and that this systematic expectation was not adjusted through time, at least not through 2002, despite the behavior of actual prices. However, throughout the rest of New York State, the opposite pattern held throughout 2002: the amount of virtual energy sales always exceeded the amount of virtual energy purchases, which meant that market players systematically expected prices to fall from day-ahead to real-time (compare Potomac Economics 2003, Figures 20 and 21, pp. 29 and 31).

In the NYC/LI area, the persistent imbalance between the quantity of virtual loads and virtual supplies should have raised questions about the maturity of this market, and the behavior of market participants, as well as basic market design. The persistence of a significant imbalance between the quantities of virtual loads and virtual supplies implies a persistent differential in the price expectations that was not eroded by arbitrage, better information, new forms of risk management, changes in market design, or other determinants of prices during 2002. These consistent patterns suggest that something was fundamentally wrong: expectations should change over time to reflect reality, especially in the case of a financial instrument defined as the difference between day-ahead and real-time energy pricing in a particular location. Market participants should see that they are systematically betting incorrectly, and should adjust accordingly. If they did not, something was getting in their way, maybe a lack of information, a market rule, a transmission constraint, or the exercise of market power.

The persistence of different bidding patterns in NYC and upstate suggests that additional investigation should have been undertaken into the behavior of participants in the virtual bidding market, especially since virtual bids were (and are) part of the LMP system in New York.[40] For example, how concentrated was the virtual bidding? At the extreme, was there only one entity submitting virtual load bids, both bidding up day ahead prices and betting on price increases in real time to create opportunities for profit, and was that one entity perhaps the same as, or affiliated with, actual suppliers of energy in New York City in real time? If so, then the seller, in cooperation with its affiliate, could place large bets that prices would rise after preschedule, and ensure the profits by economic, physical, or export withholding in real time. Although this is an extreme example, it is not without foundation, because the external monitor found that physical withholding (measured by the "output gap") in New York City was largely driven by the behavior of a single seller (see the discussion above of physical withholding), and suggested that virtual bidding could be driven by market power strategies (Potomac Economics 2003, p. 31): "[s]uch strategies could include making a large virtual load purchase in a constrained zone in order to cause congestion in the day-ahead market that would benefit the owner of [transmission congestion contracts] TCCs or other market positions." Owners of rights to cross constrained transmission paths would have an incentive to create artificial congestion. This leads to the conclusion that the behavior of specific entities in the virtual bidding market should have been investigated, to see if any of the virtual positions were correlated with the ownership of TCCs or other assets whose value could be manipulated by virtual bidding.

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[40] See New York ISO, FERC Electric Tariff, Original Volume No. 2, Attachment B, Revised Sheet 331.01.07.

Instead of such investigations, the external monitor repeated its analysis of price-sensitive virtual bids, on the theory that virtual load bids that contained an obligation to buy at prices that were "too far above" the clearing prices represented attempts to manipulate prices. Similarly, virtual supply bids that were "too far below" the clearing prices were theorized to represent attempts to manipulate prices from the supply side. "Too far above" was defined as three times the market clearing price; "too far below" was defined as less than one third of the market clearing price (Potomac Economics 2003, p. 31). Again, this analytical approach is almost tautological: "too far above" and "too far below" were defined such that a relatively small proportion of the total virtual bids would be labeled as "price insensitive" and thus as "attempts to manipulate prices". Given that there could be many reasons for virtual bids to be submitted that were significantly different from market clearing prices, and that there was no attempt (at least in the report) to investigate the behavior of entities submitting both virtual and "real" bids, the limited approach that only considers "insensitive bids" did not really answer the question. This may be another example of a "small amount of market power going a long way", because virtual bids were allowed to set LMPs in New York.

Problems or possible anomalies also showed up on the demand side of the market in 2003. The NY-ISO had several different ways for loads to participate in the market: (a) physical and financial bilateral contracts, (b) fixed load bids without regard to price,[41] (c) price-capped (i.e,. "up to $X/MWH") load bidding, and (d) net virtual purchases (the excess, if any, of virtual load bids over virtual supply bids). In reality, scheduled load

[41] The external monitor points out that this was economically irrational (p. 30), which is strictly true but raises questions about why loads would submit such "infinite price" bids. Some further investigation into this demand-side bidding behavior was clearly required.

exceeded actual load because of virtual bidding, which suggests that market participants on average persistently expected prices to increase in real-time from day-ahead, and that this expectation did not change during the course of the year. In fact, the "day-ahead premium" in NYC was negative throughout the year: day-ahead prices were <u>less than</u> real time prices, which is the opposite of intuition and the opposite of the pattern upstate. This can be explained by strategic behavior in the day-ahead market aimed at driving <u>up</u> day-ahead prices consistently. If profits in the day-ahead market exceeded losses in the real-time market, this would be a rational strategy.

This problem continued in 2003, but was explained by "inconsistencies" in the computer models relative to market operations (Potomac Economics 2004, p. 46):

> The primary cause of real-time congestion costs are [sic] changes in transmission limits between the day-ahead and real-time markets, or changes in loop flows that cause the day-ahead schedule to be infeasible. In this case, the ISO must purchase additional generation in the constrained area and sell back generation in the unconstrained area (i.e., purchase counter-flow to offset the day-ahead schedule).

The cost of the additional purchases by the ISO was socialized over loads, giving the generators in the constrained area the incentive to hold back generation in the day-ahead market. This had the effect of increasing congestion flowing into NYC and driving up day-ahead prices. The persistent pattern of virtual load bids exceeding virtual supply bids in the NYC/LI area implied that market participants expected real-time prices to exceed day-ahead prices, which they attempted to arbitrage, and that entities (or their affiliates) may have been submitting virtual load bids in an attempt to increase day-ahead prices. Also, consistent with the difference between day-ahead and real-time prices, real-time congestion into NYC was consistently less than day-ahead congestion (Potomac Economics 2004, Figure 29, p. 47). These patterns of behavior and performance were consistent with the use of virtual load bids in the day-ahead market to drive up day-ahead prices. The persistence of this pattern over a year should have triggered concerns.

Although it is important that the computer models all use the same, accurate assumptions regarding the availability of transmission capacity (to the extent possible given the different time frames for which the models are run), the behavior of generators in NYC should have been examined in more detail to determine if the persistent patterns noted above were caused by attempts to manipulate prices. For example, there was no information in the external monitor's report about the identity of those submitting virtual bids and day-ahead generation schedules. If there was an opportunity for collusion within the market rules to increase profits, it is safe to assume that such collusion would have occurred. The fact that congestion costs and the day-ahead revenue shortfall were both increasing from 2001 through 2003 suggests that markets were not operating as intended or designed (see Potomac Economics 2004, Figure 28, p. 46).

VI. New England: Optimal Withholding

One significant characteristic of New England is (still) the presence of persistent "load pockets": geographical areas, such as Boston, that are dependent on imported energy. Any generators located in such load pockets could potentially exercise market power during lengthy periods, if loads exceeded import capacity.[42] In order to maintain reliability, the grid operator (New England ISO) was forced to negotiate with such generators, who were sometimes dispatched "out of merit order" (i.e., at higher cost than substitutes) due to transmission constraints. Bilateral negotiations were sometimes triggered by "anomalous" behavior on the part of bidders. From mid-1999 through early 2001, the ISO reported 14 incidents of such behavior involving 13 market participants. Some reserve bids increased abruptly from $0.48 to $9,993, some energy bids jumped to almost $10,000, and one offer was submitted for an external dispatchable energy contract at $10 million. (See ISO New England 2001, Figure 31.) The negotiations apparently reduced these payments[43], but whether the result was competitive was not known because the ISO reported no analysis, and the nature of the negotiations was opaque.[44]

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[42] The HHI values reported in Ethier 2003 and 2004 suggest that market concentration fell significantly over time, if the entire New England Power Pool is defined as the "market". However, due to transmission constraints, not all generators are available at all times to supply load anywhere in New England, so Ethier (2003) also provided HHIs for eleven "transmission areas" for May 1999, May 2000, and December 2002. These indicated severe concentration in almost every transmission area. The RSI indexes presented in Ethier (2003) were not geographically differentiated, so do not permit conclusions about the potential for individual suppliers to influence prices in specific locations. The Lerner indexes presented in Ethier (2003 and 2004) generally confirm the results of Bushnell and Saravia (2002, p. 20): energy clearing prices on average exceed competitive benchmark prices, depending on the methodology by up to 17 percent. The results for 2003 did not differ noticeably from those for 2002.

[43] "The total unmitigated uplift cost for the first and second quarters was $3.0 million and $18.2 million, respectively. This compares with a mitigated cost of $1.7 million and $7.1 million. The mitigated/negotiated uplift was $1.9 million and $14.1 million." (p. 17)

[44] "The principles used in the ISO negotiation meetings with Participants adhere to the spirit of the transmission congestion mitigation elements of MRP 17, Section II. That is, negotiated transmission uplift compensation for those generating units that normally run in merit order is limited to their short run variable costs (i.e., fuel costs & other related costs that are incurred due to ISO dispatch for transmission congestion) while for those units that normally run out of merit for transmission reliability purposes, both variable and fixed costs are considered. Variations from this categorical approach to congestion uplift compensation have also been identified. A prime example are generating units that, due to moderate or severe, daily or annual, environmental emission limitations face a limited number of hours of generation in the energy market. In order to maximize revenue from this limited generation, bid prices higher than costs have been submitted in order to reflect the unit's opportunity costs (i.e., expected future energy market price curve). Such factors are also considered in the transmission congestion negotiations." (ISO New England 1999, p. 17)

Load pockets, or "Designated Congestion Areas" (DCAs), are characterized by high concentration, non-competitive conditions, and generators identified as needed for reliability and hence operated out of merit order. In these load pockets, the threshold for mitigation was a monthly calculation of a proxy combustion turbine. In other words, units in load pockets were not paid based on their cost of service, but based on a generic cost of service of a new simple cycle combustion turbine (SCCT, with a 10,500 BTU/KWh heat rate). Any inframarginal generating units in DCAs therefore received rents equal to the difference between the fully allocated cost of the proxy SCCT and their own costs. Given that under traditional rate-of-return regulation, suppliers were not paid based on the total cost of a new marginal resource, it is hard not to conclude that such proxy prices would yield supercompetitive returns. Some generators in load pockets (DCAs), on the other hand, might not receive payments sufficient to cover their full costs, depending on what the units' fixed costs are. For example, if a DCA unit was sold to an independent owner at a premium over the fixed costs of the proxy CT, then the unit might not receive any return on its investment. Also, if the DCA unit was sold to an independent owner at a premium over net book value, it might receive a return higher than would be implicit in traditional rate-of-return regulation, resulting in higher prices to consumers. This program was thus incapable of ensuring either reasonable returns to investors or reasonable rates to consumers.

In addition to DCAs, the ISO had to address the potential for withholding. The first report issued by the external monitor covered operations of the ISO's energy markets in 2001.[45] One premise of the report was that price spikes associated with the steep portion of the supply curve could be the result of competitive market forces rather than the exercise of market power. However, the report did not consider the nature of the market behavior during periods when demand rose to intersect with the steep portion of the supply curve (Patton et al. 2002). After reviewing the theoretical basis for physical withholding (see Klemperer and Meyer), the report reached the following conclusions (Patton et al. 2002, p. 9):

> Withholding will depend primarily on two factors. First, withholding will depend on the level of [competitive output]. Assuming the portfolio of generating units are [sic] similar from firm to firm, [competitive output] should be directly correlated with the size of the firm. . . . Second, withholding will depend on the sensitivity of prices to supply shifts (dp/dS), which defines the slope of the supply curve.

The two determinants of optimal levels of withholding are relatively straightforward. According to SFE theory, optimal withholding will (1) increase with the competitive quantity of output for any individual firm or supplier, (2) increase with the excess of actual price over the marginal cost at the output associated with optimal withholding, and (3) increase as the aggregate supply curve becomes more inelastic.[46]

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[45] The summer 2001 pricing report provides a basic introduction to the operation of the ISO-NE energy markets (Patton 2001a). However, because of a misunderstanding of the nature of auctions, the external monitor concluded that the auction type chosen by the ISO ensured efficient dispatch:

> [e]fficient prices are generally achieved through a uniform second-price auction as suppliers, absent market power, will offer resources in the auction at their marginal costs. The auction produces a competitive outcome with a clearing price equal to the bid of the marginal supplier, with all suppliers with lower bids being dispatched. (Patton 2001a, p. 3, footnote deleted)

In fact, the New England auction was not a second-price auction in the summer of 2001. That is, the ECP was set by the bid of the marginal supplier, not the supplier offering the bid that was closest to (in this case, just below) the bid of the marginal supplier. Second-price auctions can provide important incentives for bidders to reveal accurately their marginal costs. If New England had adopted a second-price auction, it might have been reasonable for the external monitor to conclude that the resulting ECPs reflected marginal cost.

[46] See equation (2) on p. 9 of Patton et al. 2002.

Data on each of these determinants of optimal withholding should be available from the NE-ISO, which has the ability to estimate the costs of each generating unit in the ISO's territory and thus the elasticity of aggregate supply, and has information on actual prices. However, as in New York, the external monitor chose an indirect route to estimate the extent of physical withholding. First, the monitor tied the incentive for physical withholding to the size of the firm. As noted in the discussion above of the New York markets, there is no theoretical basis for the assumption that competitive output is correlated with the size of the firm; in fact, non-competitive conditions are required to posit this relationship. Larger firms relative to the market have an increased incentive to withhold (in total dollars of rent transferred) if withholding of the marginal unit (economic or physical) would increase the price received by all their other units. It is the nature of the portfolio of the marginal supplier that is important, not just the size of the supplier. Instead of firm size, the external monitor should have examined the level of output at competitively determined prices.

The analysis of economic withholding used the "output gap" approach, which depended critically on estimated prices tied to reference bids during periods when markets were determined to have been reasonably competitive (Patton et al. 2002, p. 15). The output gap for any given generating unit was defined (Patton et al. 2002, pp. 13-14) as the difference between (a) the economic level of output given the current energy clearing price (ECP) and (b) the greater of the actual output or the amount of output bid at the ECP. An increase in the "output gap" could imply an increase in withholding. The reason for subtracting the greater of actual production or the amount bid at the ECP was to eliminate amounts of energy that were bid but not produced, for example due to transmission constraints.

The difficulties with this approach were identified above regarding New York. In New England, the output gap generally fell with higher loads, suggesting less withholding, although the gap was highest when loads were approximately at the "elbow" in the aggregate supply curve (Patton et al. 2002, Figure 3, p. 18)[47]. This could be evidence of a lack of deliberate withholding, as the external monitor concluded, or it could be the result of other factors. For example, given that the incentive to withhold increases as demand increases and the supply curve becomes more inelastic, the highest amounts of the "output gap" could have been driven by deliberate withholding behavior. That is, any decline in the output gap with higher demand might have been determined by New England's mitigation procedures under Market Rule 17, must-run orders, a general recognition that reliability criteria might be violated, or a desire not to be held responsible in the event of an interruption in the supply of electricity. Sellers may have been exercising economic withholding as much as they thought they could, subject to constraints on their behavior when loads neared peak levels (i.e., "optimal withholding").[48] Unfortunately, the monitoring reports did not investigate these possibilities.

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[47] The "elbow" in the supply curve is the point where the curve begins to rise steeply because meeting loads at these levels requires the use of increasingly inefficient generation units. If the output gap peaked at the elbow, this suggests a concave function, and the possibility of a profit-maximizing output gap.

[48] Physical withholding was addressed in the report for 2001 by the examination of short-duration, unplanned, or forced, outages. Using basically the same approaches as were applied to economic withholding (i.e., comparing forced outages with total demand and size of participants, both parametrically and econometrically), the external monitor reached the same conclusions: physical withholding was not a problem in New England in 2001. However, these conclusions suffer from the same limitations noted above for the economic withholding analysis: the arbitrary assumption that bids up to $100/MWh above marginal cost did not constitute economic withholding.

VII. Conclusions

All three RTOs reviewed here failed to adhere completely or accurately to standards of the theory of workable competition; even when standards were applied, the monitors reported overall conclusions that were at odds with the evidence presented. In addition, the SCP paradigm was not applied in any discernable manner. Despite repeated assertions that markets were competitive, the monitors provided evidence to the contrary. In PJM, nodal price differences increased over time, suggesting that the markets were fragmenting. Generators were caught withholding capacity. Prices were allowed to spike to reflect "scarcity", subject to arbitrary caps that were several times as high as the marginal cost of the most expensive generating unit in PJM, yet the monitor concluded that short-run revenues were at times insufficient to induce entry. The incidence of pivotal suppliers increased over time, while the availability of data fell over time. Suppliers "gamed" the nodal price system by exporting and re-importing power simultaneously. Arbitrary operating constraints were used to evade price caps. Finally, virtual schedules were used to increase the value of FTRs. These are characteristics of non-competitive markets, notwithstanding all claims to the contrary.

In a broad sense, the reports for New York were similar to those of PJM. Although markets were declared competitive, ample evidence was presented to the contrary. Some products (e.g., ten-minute NSR) experienced withholding. Prices spiked to levels above marginal costs. Analyses used arbitrary rules to exclude bids, leading to biased statistical results. Very broad conclusions were based on very limited data. The relationship between day-ahead and real-time prices was not consistent with the predictions of economic theory in many months of 2000. The analysis of persistent and counterintuitive power flows with adjacent control areas did not consider whether suppliers would purposely export power at a loss without some means of offsetting such losses through higher prices inside New York. Arbitrary thresholds were used to assess physical and economic withholding, allowing potentially flawed market designs to drive the economic analysis. Sellers of ten-minute NSRs were able to extract $70 million in excess profits in a few months during 2000, without any negative consequences. Economic withholding was practiced in the market for regulating reserves. The analysis of virtual bidding defined the problem away by limiting the data examined, while overlooking persistent patterns of virtual bidding that suggest strongly that bidders were driving up day-ahead prices. Prices in New York City required constant mitigation. Conclusions about incentives for entry were unfounded. Offer requirements were necessary for certain ancillary service markets to function, suggesting that market forces alone were insufficient to meet reliability criteria. Finally, the ISO's computer models were often blamed for anomalous behavior, while the behavior of the market participants themselves went uninvestigated.

The reports for New England demonstrated that monitoring relied on private negotiations with bidders, making mitigation of localized market power opaque at best. The market rules adopted in New England ignored the "repeated game" nature of the ISO's auctions. In any event, the monitor's job was increasingly difficult to perform because of diminished access to data on costs. The transition to Standard Market Design in 2003 required renegotiation of contracts to avoid artificial congestion, but the impact of the new arrangements on overall efficiency was unknown. Some virtual bids were found to have violated the market rules. Application of the HHI did not consider whether markets were properly defined in the first place. Energy clearing prices have generally exceeded marginal costs. Special pricing rules for load pockets interfered with virtual bidding, which otherwise may have arbitraged away price differences. Thresholds for potential withholding behavior were arbitrary and, as in New York, provided suppliers the opportunity to earn up to $100/MWh over marginal cost before triggering investigations (the results of which were secret in any event).

These monitoring reports provide substantive evidence that the restructured markets were not workably competitive, while simultaneously proclaiming the opposite. Based on the available evidence, these markets did not meet the criteria of "workable competition", and demonstrated significant flaws that required constant market redesign or the imposition of new forms of price regulation. In addition,

- there was no analysis of the relationship between the number of traders and economies of scale or scope; it may be that the portfolios assembled by market participants were larger than necessary to capture economies of scale or scope, thus reducing competitive forces;
- there was been no analysis of whether entry increased effective competition, or whether the additional generation is being built by incumbent suppliers; evidence suggests that concentration in some cases was <u>increasing</u> at times where loads were relatively high, despite entry;
- because of the repeated nature of the daily auctions, the high likelihood of shared knowledge of competitors' cost structures, and the small number of suppliers under conditions of high demand, opportunities for collusion existed that were not investigated;

- contracts and mitigation programs such as RMR contracts and DCA/PUSH programs did shield potentially inefficient suppliers, although in the service of reliable operations; and
- no analyses of the actual *economic* profitability of incumbents were reported; in their place, *pro forma* analyses comparing (only some of) the revenues available in RTO markets with the total cost of a new entrant were performed, but these could not demonstrate that profits earned by incumbents are "just sufficient to reward investment", as the theory of workable competition requires.

Several types of standard analyses were simply missing from the monitors' reports: bidder portfolio structure; interactions between physical and virtual bids; and evaluation of actual returns to suppliers compared with competitive (risk-adjusted) standards. Simple indexes were substituted for the kinds of analyses that should be uniformly and continuously applied, such as pivotal supplier(s), investigations into bidding behavior, and examination of the portfolios of bidders. By accepting these flawed reports, FERC fundamentally abdicated its responsibilities to ensure that wholesale electricity prices in restructured markets were just and reasonable.

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