Best Practices in Market Monitoring

A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets

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1. Introduction and Summary

Market monitoring and mitigation is widely recognized as an important evaluative tool for understanding the performance, and ensuring the competitiveness, of bid-based regional electricity markets. Both the physical complexities of the electric bulk power system and the administrative complexity of the market rules for competitive wholesale markets contribute to the numerous market failures that have occurred in the four years since FERC Orders 888 and 889 opened wholesale power markets to widespread competition.

The analysis in this report occurs against the backdrop of Order 2000 and its related follow-on orders on specific proposals for Regional Transmission Organizations (RTOs). Most recently, FERC directed the stakeholders in three existing ISOs to engage in a 45-day mediation process to develop a "business plan" for the development of a Northeast RTO that administers a single Northeast market with a single Northeast transmission rate. While approving parts of the individual ISO filings on RTO formation, FERC found that the "size and scope" criteria, one of the four essential characteristics of an RTO, could only be met through a larger Northeast RTO entity. To guide the mediation process, FERC directed stakeholders to use the PJM system as a "platform" from which to build the Northeast RTO, and to supplement the platform with "best practices" from NE and NY.[1]

While we have examined market monitoring procedures in numerous bid-based wholesale markets, we have focused primarily on the three northeast ISOs and to a lesser extent California.[2] For the United States, these ISOs have had the most substantial experience with bid-based markets. Due to FERC's recent RTO Orders, the three northeast ISOs are a natural focus as plans to implement a Northeast RTO are considered. NY and NE have much more extensive monitoring activities (in part due to their bid-mitigation authority), which PJM may want to consider as enhancements to its own processes, whether in the context of a Northeast RTO, or for direct application to the markets that PJM currently administers.

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[1] On September 17, 2001, the FERC Administrative Law Judge in charge of the 45-day mediation issued his Report together with a Business Plan for the formation of a Northeast RTO. FERC allowed comments on the Report to be filed through October 9, 2001. It is anticipated that FERC will issue an Order on the Report in early November. The Business Plan identifies numerous issues related to Market Monitoring, but does not make any substantive recommendations.

[2] We looked briefly at the Texas ISO and the proposed Midwest ISO but did not evaluate either one in detail due to the limited market experience of Texas and the absence of market experience for the Midwest ISO. Internationally, we examined the markets in the United Kingdom, Nord Pool (Norway, Sweden, Finland, and Denmark), Germany, and Australia. A summary of this review is attached as Appendix B.

The key themes and recommendations of this report can be summarized as follows:

The market monitor should be independent and charged with a "public interest" responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

Recommendation #1: The MMU must closely monitor, and ideally be physically present or adjacent to, the control room dispatch.

Recommendation #2: The MMU should report within the RTO to the Board of Directors. The MMU should work closely and collaboratively with the CEO and the RTO staff that has market design responsibilities.

Recommendation #3: The RTO should contract with an independent Market Monitor (IMM) or Market Advisor to complement and advise an internal MMU. The IMM should report directly to the Board of Directors of the RTO.

The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

Recommendation # 4: The MMU should be responsible for monitoring all wholesale markets administered or facilitated by the RTO/ISO, including the spot and bilateral energy, ancillary-services, capacity, and transmission markets. The MMU should monitor both supply and load bids in all markets.

Recommendation #5: As part of its ongoing evaluation of market efficiency and competitiveness, the MMU should evaluate the performance of the markets against the outcome of a market where all bids are at marginal cost.

Recommendation #6: The MMU should have the authority to assess the impact on the market of proposed mergers and acquisitions, and be a party to such proceedings.

The market monitor should have authority to mitigate, sanction, and penalize, as well as the ability to identify necessary rule changes.

Recommendation #7: The MMU should have access to all data that will assist it in performing its market monitoring function.

Recommendation #8: The MMU should have authority to mitigate any bid in any market prior to accepting it.

Recommendation #9: Bid caps should be used as an essential component of electricity markets.

Recommendation #10: In addition to its authority to mitigate a bid in advance of accepting it, the MMU should also have the authority to impose sanctions or penalties on market participants for specific behaviors, including the failure to provide information requested by the MMU.

Recommendation #11: The MMU should have the authority to flag clearing prices and make price corrections for a limited period of time after the market clears.

Recommendation #12: The MMU should have the authority to file with FERC for changes to both market-monitoring rules and market rules.

The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

Recommendation #13: In order to improve transparency and enhance confidence in the markets, the MMU should regularly and frequently issue detailed reports on its monitoring activities.

Recommendation #14: Bid data with names should be released on a one-month lag.

In conclusion, our review of current market monitoring and mitigation practice indicates that market monitoring activities need to be broadened and enhanced to guard against significant anti-competitive activities by market participants, including exertions of market power. Of particular importance is our observation that bid-based market systems do not produce prices that are "just and reasonable" when demand approaches or exceeds available supply.[3] The market monitoring improvements identified in this report are needed now and are not dependent upon any specific proposals or alternatives currently being discussed in the context of the Northeast RTO mediation process. In fact, a strong argument could be made that enhanced market monitoring and mitigation practices are a pre-condition for the creation of a single Northeast energy market.

2. Experience and Trends in Market Monitoring

2.1 The Need for Monitoring of Electricity Markets

With economic deregulation of wholesale electricity markets, there is an urgent need for aggressive market power monitoring and mitigation. In markets for other commodities, we rely upon the responsible state and federal agencies to promote workably competitive markets through enforcement of antitrust laws. Actions can be taken by antitrust

[3] Throughout this text we use the term "demand" to mean electrical requirements including reserve requirements, and the term "supply" to mean generation and operating reserves. Our focus on times when demand approaches or exceeds available supply does not imply that market prices are necessarily just and reasonable at other times. Indeed, there may be significant opportunities for market manipulation during less constrained times.

authorities in situations with collusion, proposed mergers, or monopolies. In electricity markets there are several compelling reasons that this customary approach is not adequate or prudent.

First, the electric industry is in a transitional period, with many decades of experience as regulated monopolies. The existing companies are large, with infrastructure designed and built to serve customers in transmission system control areas where there was no need to consider promoting competition. There was an extraordinary degree of industry cooperation – with individuals routinely participating on committees to coordinate system expansion and operation (e.g., the North American Electric Reliability Council). While this was appropriate and necessary in the past, going forward there are inherent tensions between the benefits of coordination and the need for firms in a deregulated market to act competitively. With respect to market power monitoring and mitigation, it is useful to keep in mind that most of the individuals currently working in this industry come from a tradition of cooperating monopolies. Market participants have, for example, played a very active role in designing and modifying electricity market rules in the new ISOs. While this may have occurred for legitimate reasons, it does point to the need for market monitoring and mitigation by an independent entity.

Second, the role of electricity as a fundamental element of the infrastructure supporting the economy as well as basic human activities should be considered. Events in California have illustrated the need for reliable electricity service at reasonable prices, and the implications to local and regional economies of power outages and sustained wholesale prices above competitive levels. It is not an easy task to sort out the specific roles of particular underlying factors (e.g., capacity shortages vs. anti-competitive withholding of generation) in the California debacle. Still, it is clear that the exercise of market power played some substantial role in causing California's problems and that aggressive, timely, and effective market power monitoring and mitigation would have been helpful.

Third, a combination of physical characteristics of electricity generation and transmission make market power a particularly urgent concern in electricity markets. Specifically:

- Electric power must be delivered over a constrained transmission grid,
- Electricity supply and demand must be balanced on an instantaneous basis, and
- Storage of electricity is limited, inefficient and expensive.

Even in electricity markets where generation ownership is not concentrated as a general matter, there are likely to be locations ("load pockets") and times for which there are an insufficient number of competing generators.

Fourth, electricity markets are characterized by repeated organized interaction, with bids typically submitted on a daily basis, and refinement on an hourly basis (in "day-ahead" and "real time" markets). Markets that function as a repeated game are particularly subject to tacit collusion, as participants learn about and react to the bidding strategies of other participants, or even use the bidding process to communicate and promote cooperation (see, for example, Gibbons 1992).

Fifth, market entry is difficult in electricity markets. It can take several years to get a power plant built, given difficulties in siting, obtaining permits and financing, lining up fuel supply, and construction. Power generation is capital intensive, with new combined-cycle gas plants costing in the neighborhood of $600/kW. In other markets, where market entry is quicker and less costly, actual market entrants or even the threat of entry may be relied upon to moderate the exercise of market power. In electricity markets, the role of market entry must be supplemented by effective market monitoring and mitigation.[4]

And finally, the lack of demand participation in electricity markets is noteworthy and troublesome. In the short run, electricity demand is almost entirely "inelastic." That is, when pool prices spike there is little practical opportunity for customers to cut back purchases. This is changing gradually, with demand-response programs being developed and expanded in all of the operating ISOs (Synapse 2001) but we are still many years – probably decades – away from an adequate demand response in electricity markets. In the meantime, aggressive market monitoring and mitigation supplemented by bid caps will be essential elements of electricity markets.

In electricity markets, the continuing obligation of generators to serve loads (either under contract or as a continuing obligation of a vertically integrated company) can help to decrease or eliminate the incentive for a company to bid above marginal costs in order to raise the market price. In PJM, unlike California and New England, a large amount of the generating capacity has continued to be owned by companies with substantial load obligations. As PJM's 2000 State of the Market Report notes:

> The structural analysis indicates that the PJM control area exhibits moderate market concentration. However, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2000, primarily due to the load obligations of the generators in those areas, but a significant market-power related risk exists going forward should those obligations change.[5]

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[4] For a discussion of market entry, as well as an excellent overview of experience in electricity markets through the beginning of 2000, see "Horizontal Market Power in Restructured Electricity Markets" (DOE, 2000).

[5] PJM 2000 State of the Market Report, p. 11.

2.2 Regulatory Context

Orders 888 and 889

In Orders 888 and 889, issued in April 1996, FERC introduced new opportunities for competitive markets to replace traditional cost-based regulation of wholesale bulk power systems. As a result of those Orders, FERC set a series of events in motion that have led to both the need for a report such as this one and to many of the practices that this report recommends. In its April Orders, FERC required that:

- All owners of transmission systems had to file an Open Access Transmission Tariff (OATT) that would provide universal and non-discriminatory access to the use of the bulk power electric system for wholesale electricity sales.

- Electric utilities were allowed and encouraged to develop proposals for "independent system operators" who could oversee the implementation of the OATT on a fair and impartial basis and who could administer a wholesale market in a manner, subject to FERC approval, that would produce "just and reasonable" rates.

Despite FERC's concern that market based rates might provide an opportunity for the exercise of "market power" by owners of generation resources, FERC stated that it would approve market based rates upon satisfaction that the exercise of market power was either unlikely, or that structures had been proposed to guard against such exercises. From this initial posture of "let's see how it goes," FERC has approved a series of increasingly more detailed and complex market monitoring proposals over the ensuing years.

Order 2000: RTOs

In December 1999, FERC issued Order 2000, which required all entities that implement open access transmission tariffs to file proposals for creating a regional transmission organization (RTO) that satisfied the four characteristics and eight functions detailed in the Order.[6] Filings were required in October 2000 for transmission tariff entities that were not part of an existing ISO; the ISO transmission entities were required to make their filings in January 2001.[7] For the purposes of this report, the second characteristic, independence, and the sixth function, market monitoring, deserve particular attention.

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[6] The four characteristics are (1) independence from market participants, (2) appropriate scope and configuration, (3) operational authority, and (4) short-term reliability. The minimum functions pertain to (1) transmission service and tariff, (2) congestion management, (3) parallel path flow, (4) ancillary services, (5) transmission availability information, (6) market monitoring, (7) transmission planning and expansion, and (8) interregional coordination. Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999).

[7] PJM and the transmission owners filed their RTO proposal early, on October 11, 2000.

FERC highlighted the need for RTO independence from market participants to ensure that the wholesale electricity markets and the associated transmission service would not be subject to manipulation or undue influence from entities engaged in profit-making activities. A truly independent RTO would create confidence among market participants that there was a level playing field; it would also encourage new entrants into both the market and transmission functions of the wholesale regional marketplace.

FERC identified market monitoring as one of the core functions that an RTO entity must provide. Since Order 888, FERC has moved toward a more active approach with regard to the need for and benefits of market monitoring. However, FERC still maintains a very flexible approach to market monitoring by allowing RTO participants to identify appropriate market monitoring activities that would meet certain broad standards.

Northeast RTO Orders

In its Orders released in July 2001, FERC discussed how the filings from PJM, NY and New England addressed the "independence" characteristic and the "market monitoring" function. The orders are briefly summarized.

Independence

In the PJM Order, FERC found that PJM meets the independence characteristic except for the establishment of reliability requirements (including capacity resource obligations and capacity deficiency requirements) pursuant to the Reliability Assurance Agreement. For determining reliability criteria under the RAA, FERC stated that PJM can not allow these requirements to be set by a committee of market participants. In this Order, FERC did not specifically address the role that market participants have under the PJM Operating Agreement in proposing and approving changes to the market rules.

In the NYISO Order, FERC found that the authority of market participants, through a governance committee, to review and approve all changes to the wholesale markets system was inappropriate and created "undue influence" on the part of market participants. FERC found that NYISO's RTO proposal failed to meet the independence characteristic.

In the ISO-NE Order, FERC found that market participants' role in governance, through the NEPOOL committee process, was inappropriate. In an RTO, a committee of market participants, such as NEPOOL, should serve a purely advisory role. FERC specifically mentioned NEPOOL's role in approving changes to market rules and stated that this should be the exclusive authority of ISO-NE.

Market Monitoring

The implications of the Orders for market power monitoring and mitigation are not clear. FERC emphasizes that it will be paying close attention to, and will be involved in, on-going efforts to monitor markets. FERC found that all three proposals satisfied the market monitoring function, although ISO-NE must make a supplemental filing once it has implemented a congestion management system.

It is worth noting that the market monitoring plans of the three Northeast ISOs differ significantly. PJM's market monitoring unit has a small staff and no general authority to mitigate bids or impose sanctions and penalties; it performs primarily a monitoring function, only. However, PJM has the authority to cap bids of must-run units in local load pockets, which is done outside of the market monitoring process. FERC states in the PJM Order that it is not essential for an RTO to have mitigation authority, and accepts PJM's proposal, which does not include a request for mitigation authority.

ISO New England currently has bid mitigation authority that was won with a strong effort on the part of PUCs and AGs in New England. ISO-NE has a medium sized staff and the authority to mitigate bids before the market clears, impose sanctions and penalties, and also mitigate congestion payments for generators in "non-competitive" conditions.

In the New York Order, FERC approved the NYISO's proposal and specifically mentioned the appropriateness of its market mitigation and sanctioning authority. NYISO has the largest staff and the most extensive monitoring and mitigation process of the three ISOs. Furthermore, NY and NE have "outside" market advisors – entities that advise the ISO Board but are not within the ISO corporate organization, while PJM does not.

The disparity in market monitoring authorities and practices is important, and FERC has not given any clear guidance on how the market monitoring function should be designed for the Northeast RTO. Since FERC identifies PJM as the platform upon which the Northeast RTO should be developed, it remains unclear as to whether there will be consistency between the market monitoring functions of the three control areas. While best practices of other ISOs are to be incorporated into the PJM market platform, FERC has not clearly stated how the NE RTO market monitoring function is to be designed nor identified any of the market monitoring "best practices" from NY and NE that should be added to PJM's RTO proposal for market monitoring.[8]

2.3 ISO Experiences

Market Monitoring Concerns during ISO Formation

As the ISO's were established in the Northeast electrical control regions, each took a slightly different perspective on the need for, and implementation of, market monitoring.

PJM's proposal for market based rates for a multi-state tight power pool included a study by independent economists that PJM's markets were not "concentrated" and there was unlikely to be an opportunity for existing generators to have or exercise market power.

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[8] FERC, *RTOs – Administrative Law Judge Mediator's Report to the Commission*, Docket No. RT01-99, September 17, 2001, p. 7.

Despite some protests by intervenors in the FERC proceeding, FERC agreed in large part with PJM's claims.[9] At the time of market implementation PJM had only a small market-monitoring unit with no mitigation authority and no authority to impose sanctions. However, PJM required cost-based bidding for the first year of the markets, as well as a bid-cap of $1,000 that is still in effect. In addition, PJM had the authority to manage prices in load pockets by capping the bids of must-run generation. Furthermore, due to the limited amount of divestiture of generation units, most owners of generation had significant load obligations, which would act as a restraint on bids.

In New England, market participants also asserted that market power concerns were minimal. As part of its filing for market based rates, the New England Power Pool ("NEPOOL")[10] included a study by independent economists that found that under most scenarios, the New England wholesale market was not constrained and that concentrations of generation ownership were not so high as to warrant concerns about the possession or exercise of market power. In response to intervenor comments that challenged NEPOOL's study, however, FERC ordered NEPOOL, the new ISO, and state regulatory agencies to develop a market rule that would allow for appropriate and effective market monitoring and mitigation, including the authority to impose sanctions on market participants.[11]

New York filed its proposal for market-based rates after PJM and New England. As part of its proposal, NY included a market-monitoring unit within the ISO and an independent Market Advisor who sat outside the ISO and reported directly to the ISO Board. FERC approved this arrangement in late 1999.

Post-formation ISO Experiences

As ISOs and market participants have gained experience with electricity markets, and as those markets have evolved over the past few years, ISOs and other stakeholders have modified and sought to improve market monitoring practices and procedures. Comparison of these experiences provides an initial basis for identifying necessary components of effective market monitoring authority and procedures.

In this Section we will discuss key aspects of the experience of the four ISOs in the US that have been up and running. We will also describe some of the more notable market failures and problems that have occurred in each of the four US ISOs. We begin with

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[9] 86 FERC 61,248, March 10, 1999.

[10] NEPOOL consists of the owners of the generation and transmission facilities in the New England control area, as well as the participants in the wholesale markets and various other stakeholder entities.

[11] The immediate result was MRP 17 (Market Monitoring and Mitigation), but MRP 13 (Sanctions) and MRP 15 (Price Correction Authority) also reflect the directives in FERC's Order

California because it was the first to institute a competitive, bid-based wholesale market.[12]

California

There has been an on-going effort to ensure that prices in California's electricity markets are consistent with efficient competition. California experienced problems with its ancillary services markets right from the beginning. Bid-caps were imposed in 1997/98 in an effort to control exorbitant prices. The energy market experienced problems due to the limited transfer capability of the transmission system, particularly between Northern and Southern California. Price caps were relaxed, as the problems were resolved.

In 1999 and 2000, the problems in the energy market became so severe that $1,000 prices and rolling blackouts began occurring with regularity. Since the beginning of the competitive wholesale markets in California, CA ISO (through its Department of Market Analysis "DMA" and its Market Surveillance Committee "MSC") has closely examined the wholesale markets in California. Prior to the spring of 2001, CA ISO primarily identified the potential for market manipulation under a variety of circumstances and sought structural fixes to prevent the potential for exercise of market power. Similarly, FERC staff studies and FERC Orders state in broad terms the potential for the exercise of market power and that it appears market power has been exercised.

In contrast, in spring 2001, CA ISO analysis identified specific evidence of the exercise of market power by specific market participants in filings in docket EL00-95. Simultaneous with FERC's investigation of specific bids above the soft cap established in December 2000, CA ISO analyses established links between bidding behavior of specific market participants and non-competitive prices in California markets. Reports from March 2001 are based on specific findings regarding specific market participants and are the first reports to establish a link between individual bidding actions and their impact on market prices. These findings are supplemented in an April analysis. Both the March and April analyses make allegations against specific market participants (whose identity is held confidential). ISO submitted confidential analysis and data to FERC in support of its conclusions. These analyses are submitted in response to FERC's desire to implement prospective market monitoring, and FERC's Section 206 investigation of just and reasonable rates for the period beginning December 8, 2000; however, the analysis covers a period beginning in early 2000 and the ISO emphasizes the need to consider refunds prior to the period that FERC has identified.

In late spring 2001, FERC developed a prospective market monitoring and price mitigation plan for California. The plan, for real-time California wholesale electric markets, included the following: (1) enhanced ISO ability to coordinate and control

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[12] Nonetheless, California stands apart from the other ISOs due to the uniqueness of its market structure. PJM, NE and NY are much more similarly structured in their market designs, despite the significant differences that do exist between.

planned outages, (2) must-offer obligation for generators, (3) conditions, including refund liability, on sellers' market-based rate authority, (4) price mitigation in California and throughout the rest of WSCC during periods of reserve deficiency; (5) price mitigation in California and the West during periods of non-reserve deficiency, and (6) weekly ISO reports to FERC on schedule, outage, and bid data for all hours.[13] The price mitigation is to be achieved through bid caps. During periods of reserve deficiency, there will be a single market-clearing price established using proxy prices for each generator. Bids above the proxy price are permitted but must be justified and are subject to refund.[14] During periods of non-reserve deficiency, bids cannot exceed 85% of the highest market-clearing price during the most recent period of reserve deficiency.[15] Due to aggressive efforts in early 2001 to encourage conservation, energy efficiency, and develop initial load response programs, the decision by FERC to allow soft price caps, and below average summer temperatures, the summer of 2001 did not repeat the high prices and scarcity problems of the previous winter.

PJM

There are a number of structural and design features of the PJM wholesale market that, in combination, have served to curb systematic abuse of market power since the ISO's implementation of market-based rates in April of 1998. In particular, the opportunity to profit from market abuse has been severely limited by the fact that the bulk of the generation capacity has been dedicated to serving retail load at regulated or capped rates.[16] In addition, the requirement to bid at cost during the first year of operation, along with the phased opening of product markets, curtailed opportunities to exploit design flaws during the initial "shake-out" of the PJM markets. Finally, the PJM market design incorporated at its outset a bid cap in the energy market of $1,000 per MWh, an effective price cap in the capacity market at the Capacity Deficiency Rate, and authority to cap energy bids at cost for generators located in local load pockets.

However, the current relationship between generation ownership and load obligations is changing. More utilities are choosing to divest generation resources and arrangements for providing standard offer service under capped prices are expiring. In addition, the cost capping of bids in load pockets applies only to units built prior to July 1996. Over

[13] Docket No. EL00-95-012 et al., April 26, 2001, 95 FERC 61,115. Docket No. EL00-95-031 et al., June 19, 2001, 95 FERC 61,148.

[14] 95 FERC 61,115 (April 26, 2001)

[15] 95 FERC 61,148 (June 19, 2001)

[16] The continued obligation to serve load is a significant deterrent to behavior that would raise the market-clearing price. A utility that owns generation and has a significant load obligation is not in a position to profit from raising the market-clearing price to the extent that an independent generation company would be. The additional income for the generation resource would be offset by higher costs to supply its load (generally retail customers) and an inability to pass through those costs due to fixed rates or cost-of service regulation.

time, with new additions, the proportion of capacity exempt from cost capping will grow. However, at the November 8, 2001 meeting of the PJM Energy Markets Committee, the PJM market monitor made a proposal to collect cost data from units built subsequent to July 1, 1996, and there are stakeholder discussions underway in PJM to consider cost capping those units.

Despite the structural relationships that limit the value of manipulating prices, and rules that limit the ability to do so, the PJM markets have not been immune to the exercise of market power or gaming of market rules. Since its inception, the PJM MMU has addressed occurrences of opportunistic bidding in the energy market on high-demand days, efforts to circumvent the $1000 cap in the energy market, abuse of market power in the installed capacity market, and complaints regarding the potential for gaming in the FTR market.

Since 1999, the PJM energy market has experienced price spikes on some days where load approaches or exceeds available supply from internal resources. For example, on July 28, 1999 the market price hit $935/MWh, or more than seven times the $130/MWh marginal operating cost of the highest-cost unit on the PJM system.[17] More recently, real-time prices rose above $900/MWh every day from August 7 through August 9 of 2001. In the former case, the PJM MMU found that

> It appears clear that some generation owners, with an incentive to raise the price, did attempt to exercise market power by economically withholding the output of some units. It is also relatively clear that on July 28 the result was to increase the price of energy above the competitive market level.[18]

In the more recent case, the MMU is continuing to evaluate whether market power was exercised.[19]

In addition to these isolated occurrences of apparently anti-competitive bidding, the MMU has occasionally uncovered evidence of systematic gaming of market-design flaws. For example, the MMU identified attempts to circumvent the $1,000 bid cap with minimum run time bids. In response, the MMU implemented modifications to the rules regarding payments to minimum run time generators that foreclosed further gaming opportunities of this type.

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[17] In fact, prices exceeded $130/MWh in 96 hours, 4.3% of the hours, of the summer of 1999 (source: PJM *State of the Market Report: 1999*, page 11). According to one study, PJM energy-market costs exceeded marginal operating costs by $224 million during the summer of 1999. See Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market", University of California Energy Institute, April 2001, p. 1.

[18] PJM, *State of the Market Report: 1999*, page 36.

[19] PJM, *PJM Prices and Markets: The Week of August 6, 2001*, Preliminary Report, August 21, 2001, p. 1.

PJM administers a separate market for regulation services. Although the regulation market has experienced intermittent price spikes since its inception in June 2000, the MMU has not identified specific instances of bidder gaming of market-design flaws.

Over the last few years, PJM's installed capacity market has been plagued with the problem of daily de-listing of capacity resources. The MMU has consistently determined that such de-listing represents a rational competitive response to high market prices in regional markets bordering the PJM control area. However, because of the potential impacts on system reliability from daily de-listing, the MMU has recommended, and FERC has approved, implementation of a seasonal capacity market beginning in the summer of 2001.

One notable instance of the apparent exercise of market power in the installed capacity market occurred in the first quarter of 2001, when prices rose from approximately $2/MW-day in the prior quarter to $177/MW-day (i.e., the ceiling on capacity prices set by the Capacity Deficiency Rate –"CDR") during a period when there was excess capacity on the system. The MMU identified a flaw in the mechanism for distributing deficiency payments received from load-serving entities that are short on capacity as the cause of the run-up in prices. Since such payments were distributed to capacity owners that were long on capacity, owners that were sufficiently long had a perverse incentive to bid at the CDR. If such bids were accepted, then the market price received by the bidders would be at the CDR. Alternatively, if such bids did not clear, then the pool would be short, and the long owners would be paid the CDR anyway. In response to this design flaw, the MMU devised and implemented a new mechanism for distributing deficiency revenues that eliminated the opportunity to profit from bidding at CDR when the market is long.

Finally, the MMU has received complaints with regard to gaming in the Financial Transmission Rights ("FTR") auctions by transmission owners through the withholding of data on planned transmission outages that can affect FTR prices. Although the MMU has not uncovered evidence of such incidents, it recommended that rules regarding outage notification be strengthened.[20] Revisions to market rules governing outage notification were approved by the PJM Operating Committee.

ISO-NE

Since the inception of ISO-NE in July 1997, there has been an iterative and often very contentious process of refining and modifying ISO-NE's market monitoring and mitigation authorities through a series of market participant votes and FERC proceedings. While ISO-NE began with broad authority to correct prices as markets were launched, that authority has gradually been reduced so that it is currently restricted to revising

[20] FERC, however, issued a show cause order to determine whether PECO Energy may have given its unregulated affiliates preferential access to information that was helpful to the affiliates in bidding for FTRs (97 FERC 61,009, Docket No. IN01-7, October 3, 2001).

prices for computer software and human errors, only. [21] ISO-NE and market participants have also struggled to determine what circumstances prevent a market from being workably competitive. Specifically, this issue has been argued regarding system-wide capacity constraints, inappropriate market products, and load pockets. ISO-NE has used a variety of tools to address identified concerns with the competitiveness of the markets including recommending changes in market structure and design, recommending changes in market rules, using its emergency rulemaking authority, mitigating bids, flagging and correcting prices, and imposing sanctions on market participants.

The wholesale markets implemented in May 1999 allowed unrestricted bidding in seven markets: an energy market, four ancillary services markets, an operable capability market, and an installed capacity market. In the first weeks there were problems with generation units (mostly hydro) that bid below the Energy Clearing Price ("ECP") but were not being dispatched due to conflicts between bidding and operational (reliability) rules. As that problem was being addressed, unusually warm June weather triggered a series of capacity deficiency events that led to more conflicts between operational rules for reliability and bid-based market rules.[22] ISO-NE filed emergency rule amendments in June and July 1999, to address most of these issues. In August 1999, ISO-NE filed for elimination of the Operable Capability market as a redundant and unnecessary market. Despite vociferous protests from owners of generation, FERC approved ISO-NE's filing. On numerous occasions during that first summer, ISO-NE observed that on days when load approached or exceeded New England supply, prices in its energy, three reserve, and operable capability markets were routinely at levels significantly above those that would be expected from a workably competitive market, the Market Rule 15 standard. In response to this observation, ISO-NE requested and received from FERC a 60-day extension of MRP 15.

In the fall of 1999, FERC denied ISO-NE's request for a second extension of the price correction authority of MRP 15. FERC stated that the extensive price correction authority in MRP 15 was only intended for the initial 90-day market start-up period and that after an additional 60-day extension, it would not be further extended. FERC concluded that any changes to the market designs should be implemented through market rule filings by NEPOOL or, if needed on an emergency basis, by ISO-NE. FERC agreed,

[21] Prior to the implementation of the markets, FERC approved Market Rule and Procedure (MRP) 15. MRP 15 authorized ISO New England to flag and correct prices that "were inconsistent with a workably competitive market". MRP 15 was an interim rule (90-day sunset provision) to address problems with the design and implementation of market-based rates. Although MRP 15 is still in effect, the scope of the rule has been severely limited and the "workably competitive" standard has been eliminated.

[22] Similar to the problems in the first few weeks, the conflicts had to do with units that were "postured" (held in reserve) due to their quick response capability or limited energy availability (ponded hydro) despite the fact that their energy bids were in merit and under normal circumstances they would be dispatched for energy. The original rules had restrictions on when units were eligible to set the energy clearing price, when they could receive uplift compensation, and the manner in which units could be designated for reserves.

however, with ISO-NE's observation that due to market failures during times of capacity deficiency, the reserve market prices could not exceed the ECP.

In July of 2000, in response to a complaint from a load serving utility (one that has divested all its generation resources) about the $6,000 ECP price spikes in May, FERC capped bids at $1,000 per MWh. The complaint argued, in essence, that a market-based system did not operate properly during a capacity deficiency event. That bid cap continues today, as does a cap on ancillary-service prices.

Just as ISO-NE has gone through several iterations in modifying its price revision authority, it has gone through several stages in determining the appropriate authority and circumstances during which bid mitigation should apply. There are two occurrences that offer a striking example of the obstacles to effective market monitoring and implementation of corrective policies under current MMU rules and ISO practices.

<u>May 2000</u>

The May 2000 event involved dispatchable energy contracts that were associated with installed capacity (ICAP) entitlements. Under then existing rules, a NEPOOL Participant could receive credit in the monthly ICAP market for ICAP entitlements associated with a contract to supply energy even if the energy contract never flowed. The energy contract would have to be bid into the market every day and be available to flow (dispatchable) if called. Due to flaws in the design of the ICAP market, some NEPOOL Participants were removing ICAP offers from the bilateral market and thereby "forcing" other NEPOOL Participants to purchase ICAP requirements through the ISO administered residual spot market (which settles after the month) at significantly higher prices. In January, February, and March of 2000, ISO New England mitigated bids in the spot market after determining that the extremely high bids were, in effect, economic withholding.[23]

Several NEPOOL Participants began submitting external dispatchable contracts with extremely high energy bids in early 2000 as an alternative way to receive ICAP credit, rather than entering into a New England bilateral contract or relying on the post-month spot market. By submitting contracts with high energy bids (some as high as $10,000 per MWh), the Participant was relatively certain that the contract would never flow, but the ICAP value would be credited. ISO New England commented on this "practice" in its FERC filing.[24] In that filing, ISO New England noted that the external contracts with extremely high energy prices could be called if a capacity deficiency event occurred. On May 8th, unseasonably warm weather created extremely high demands at a time when numerous generation units were unavailable due to spring maintenance. That morning, ISO New England had dispatchable contracts in its bid stack at prices as high as $10,000. Around noontime, as New England approached a deficiency in capacity, a $6,000 bid was

[23] Docket No. EL00-62-000, ISO-NE filing of 5/8/00.

[24] <u>Id</u>. Prior to January 2000, the ISO administered spot market had cleared at $0 per MWh for the previous seven months.

dispatched and set the ECP for the next four hours. In a subsequent report, ISO-NE stated that based on prices in the NY market, it had determined that the $6,000 bid was "reasonable" and accepted it without mitigation.[25]

In response to widespread criticism of the ISO's decision to accept the $6,000 bid, ISO New England maintained that the market rules then in effect had been properly implemented. It described in detail how the rules allowed such contracts, that the contract in question met the rule requirements, and that ISO New England had an obligation to implement the rules without regard to price.[26] ISO New England proposed changes to the market rules to prevent recurrences without resorting to bid or price caps. In July, FERC adopted some of the ISO's proposed changes while installing a $1,000 bid cap and stating that markets are not competitive during capacity deficiency events.[27]

Summer 2001

On June 1, 2001, the NEPOOL Participants Committee (NPC) approved changes to the market rules to prohibit external dispatchable contracts from setting the ECP. Under the new rule, external contracts would be eligible to receive payment based on their bid prices, but would not be eligible to set an ECP that would be paid by all spot market purchasers. On June 14th, several NEPOOL Participants appealed the NPC decision to the NEPOOL Review Board, thus staying any NEPOOL action.[28] On July 10th, ISO New England filed the rules changes with FERC and requested an effective date of September 1, 2001.

On July 23, 2001, the New England bulk power system experienced a sudden loss of generation resources, which coupled with high loads due to warm weather, created an almost immediate capacity deficiency situation. ISO New England accepted all available bids, including an external dispatchable contract bid at $1,000/MWh. The ECP was set at $1,000 by that contract for two hours on Monday, July 23; for four hours on July 24; and for seven hours on July 25. ISO-NE evaluated the significant differences between the ECPs set by the external contracts and the ECPs without those contracts. The total increased cost for spot market energy in the 13 hours of $1,000 ECPs was estimated by ISO-NE to be $80 million.[29] The fundamental issue is how five-minute price increases of

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[25] ISO-NE noted that marginal prices in NY on the morning of May 8th exceeded $3,300 per MWh. Pursuant to agreements with the NY ISO for purchases of emergency power, ISO-NE would be obligated to pay 1.5 times the NY marginal price. ISO-NE reports "Events of May 8-9, 2000" (June 1, 2000) and Supplemental Report on May 8, 2000" (July 28, 2000).

[26] Id.

[27] 92 FERC 61,065 (July 26, 2000).

[28] Pursuant to NEPOOL's rules, an appeal to the NEPOOL Review Board stays the filing of rule changes approved by the NPC until the Board renders a decision.

[29] ISO Customer News, Issue #70, August 15, 2001; NPC Operations Report, August 3, 2001.

500 to 2000 percent can be the result of a properly functioning competitive market. There is also a concern as to why ISO-NE allowed the external dispatchable contracts to set ECPs on the 24th and 25th after being alerted to the situation on the afternoon of the 23rd. Given that a rule change that would have corrected this situation had already been filed with the FERC, ISO-NE could have used its emergency rule-making authority to implement the pending rule immediately.

In a report released in September, ISO-NE determined that the $1,000 prices were appropriate because they were consistent with the rules then in effect. This response is the same as the response to the May 2000 event and does not answer the question of whether the rules themselves are consistent with efficient and competitive markets.

In the two events described above, ISO New England chose not to exercise its explicit authority in the Interim ISO Agreement to ensure the "competitiveness and efficiency" of the wholesale markets.[30] Section 6.17(e) of that agreement states:

> If the ISO determines in good faith that (i) the failure to immediately implement a new System Rule or Procedure or a modification to the existing System Rules or Procedures would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the NEPOOL Market, and (ii) invoking the rulemaking procedures of the relevant NEPOOL Committee would not allow for timely redress of the ISO's concerns, the ISO may promulgate and implement such new or modified System Rule or Procedure unilaterally upon written notice to the NEPOOL Executive Committee, subject to approval by the FERC, if required.

Underscoring the importance of ISO-NE's responsibility to ensure the reliability, competitiveness, and efficiency of the wholesale markets, any rule changes implemented pursuant to this authority can become effective immediately, rather than the mandatory 60-day waiting period associated with rule changes that NEPOOL files with the FERC. While it is important to administer market rules in a consistent and even-handed manner, it is also important to change rules once they are observed to produce anti-competitive impacts.

It is important to note that FERC has not demonstrated consistent support for the ISO's execution of its authority pursuant to Section 6.17 of the Interim Agreement. In November 1999, FERC specifically referred to the ISO's emergency rule-making authority as one of the reasons that price correction authority under MRP 15 for market design flaws should be eliminated.[31] However, in a subsequent Order in July 2000,

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[30] The Interim ISO Agreement is the document in NEPOOL's 1996 FERC filing that details the relationship between NEPOOL, comprised of market participants, and ISO New England, the independent system operator.

[31] 89 FERC 61,209 (November 23, 1999).

FERC criticized ISO New England for having to resort to its emergency authority rather than achieving rule changes through the NEPOOL Committee process. FERC also directed ISO-NE to revise MRP 17 to "reduce the level of ISO discretion in determining when to apply mitigation measures."[32]

The very complex, and often very difficult, evolution of ISO-NE's market monitoring authority and practices has highlighted an increasingly sophisticated understanding of electricity markets and the conditions that permit, or hinder, "workably competitive markets."

NYISO

Perhaps as a result of the decision to implement several bid-based markets simultaneously, there have been some notable instances of opportunistic bidding behavior since the startup of the NYISO in late 1999. In response to these problems, over the last two years the NYISO has implemented bid caps and enhanced bid mitigation procedures in the energy market, suspended market-based pricing and subsequently imposed bid caps in the reserve market, and expanded the scope of the mitigation mechanisms applicable to New York City generators.

In the energy markets, a bid cap of $1,000/MWh was implemented in July of 2000 based on a proposal by the New York PSC and following the filing of a complaint by New York State Electric and Gas that called for imposition of cost-based bidding. Plagued by numerous design flaws in the first few months of operation, the NYISO Board requested FERC approval of a temporary bid cap in expectation of continuing problems in the upcoming summer period. Although initially proposed as a temporary measure, the ISO has repeatedly requested and been granted extensions of the bid cap.

The market-monitoring plan adopted at the end of 1999 authorized the MMU to mitigate energy bids that exceeded certain pre-determined thresholds. When first implemented, the MMU employed a manual procedure for flagging and mitigating bids that was too cumbersome to allow for mitigation of bids prior to their use in determining the market-clearing price for the current operating day. Instead, the MMU was constrained to applying the mitigated bid for determining price for the following day. Because of this one-day lag in mitigation, a generator could reap, and consumers would be liable for, one day's worth of windfall profits, even though the generator's bid was deemed to reflect the exercise of market power.

The events of June 26, 2000 revealed the potential for economic damage from this one-day lag in bid mitigation. On that day, prices spiked to approximately $600/MWh as a result of bids that were subsequently determined to have exceeded the mitigation thresholds. According to the NYISO, consumers bore over $100 million in excess costs

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[32] 92 FERC 61,065 (July 26, 2001).

before bid mitigation could be applied.[33] As a result, and in light of FERC's unwillingness to allow retroactive price corrections, the NYISO subsequently implemented an automated mechanism for mitigating bids prior to setting the market-clearing price. In addition, the NYISO filed for authority to impose penalties and sanctions for repeated anti-competitive behavior.

In March of 2000, the NYISO suspended market-based pricing in the operating-reserve market as a result of evidence of physical withholding and consequent dramatic increase in clearing prices. In compliance with FERC order, the NYISO subsequently restored market-based pricing, but imposed a cap on non-spinning-reserve bids.

In the New York City market, energy prices spiked on a number of high-load days even though a bid-mitigation mechanism was in place for generators that had been divested by ConEd. In response, ConEd proposed, and FERC recently approved, an expansion of the scope of the in-City mitigation mechanism to all generators located within the City.[34]

In summary, all four U.S. ISOs have discovered that their bid-based markets have design flaws that require constant attention ranging from minor adjustments to large-scale overhauls or, in some cases, to complete elimination of the market. Whenever demand approaches the limits of available supply, electricity markets experience price volatility not seen in other markets. FERC has recognized that market based rates may not be just and reasonable under such circumstances.[35] FERC's solution has been to continue the bid caps in PJM and to impose bid caps in the other three ISOs. In fact, the bid caps in NE and NY will remain in effect until the single Northeast market is implemented, at which poitn the continuing need will be reassessed. In an order concerning new bid caps in California, FERC justified the imposition of the bid caps as follows:

> ... as reserves are reduced, all sellers are aware of how tight supplies are relative to the amount they have to offer. Thus sellers have an incentive to offer supply at prices above that which they

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[33] NYISO, "Exigent Circumstances Filing of the New York Independent System Operator, Inc. At the Direction of its Board of Directors to Implement Automated Mitigation Procedure", May 17, 2001, p. 8.

[34] FERC Order on rehearing accepting revised market power mitigation measures, as modified for filing, Consolidated Edison. July 20, 2001.

[35] See, 92 FERC 61,065 (July 26, 2001). In this Order FERC explains why it is imposing bid caps "we believe such a cap is necessary to ensure just and reasonable rates this summer in these markets. We agree with NSTAR that in capacity constrained periods where OP4 conditions apply, the existing New England market does not operate in a manner consistent with a typical competitive market".

See, 97 FERC 61,095 (October 25, 2001). In this Order FERC states: "In our orders approving the previous extension of the bid cap, we noted that if load cannot respond to dramatic increases in prices, then generators can submit very high bids that NYISO must accept when supplies are tight during peak periods, and price spikes can be magnified. We found that these situations can lead to unjust and unreasonable prices if NYISO is forced to accept such high bids and load is not able to reduce its purchases at these prices."

> would ordinarily bid. Because of the imbalance of supply and demand, these prices may not be just and reasonable.[36]

3. Assessment of Current Practices

This section presents key aspects of the current market monitoring and mitigation practices of the three northeast ISOs and California. Additional detail is provided in Appendix A. Where relevant, the practices in international markets are mentioned. International practice is discussed in further detail in Appendix B.

3.1 Structure and Budget

In general, market monitoring staff and their budgets have increased significantly each year for the PJM, New England, New York, and CA ISOs. These increases have occurred as a response to the dysfunctions in each of the markets and a growing awareness of the need to monitor, for prospective long-term changes, and mitigate, for immediate correction of short-term problems.

The PJM Market Monitor has had the smallest staff (5). PJM has fewer markets to monitor than the other Northeast ISOs and it does not have the authority to revise prices or mitigate bids.[37] In contrast, New York has the most markets to monitor, the authority to review and revise prices, and the most extensive mitigation process to administer. This is probably why New York, with a current staff of 11 (similar to the staff of ten that New England desires), plans to increase its staff to 23 by the end of this calendar year. New York has acknowledged that its current staff can barely keep up with the "rapid mitigation" thresholds and has spent very little time reviewing the "slow-mitigation" thresholds. New England currently has a staff of 8, with plans to fill two additional positions.[38] New England reviews bids in its energy market and three reserve markets every day prior to accepting bids. New England, which lacks a congestion management system, also has to evaluate all flags for "out-of-merit" generation to determine if individual generator bids should be mitigated.[39]

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[36] 95 FERC 61,148 (June 19, 2001)

[37] Nonetheless, PJM is in the process of expanding its market monitoring staff by two and adding two support staff for a total of nine employees.

[38] In addition, ISO-NE has an internal "price review committee" comprised of ISO-NE employees from market monitoring, markets development, and system operations. This group makes most of the initial decisions regarding the mitigation of bids and the flagging of prices for possible revision later.

[39] This burden has diminished somewhat as reference screens have been developed for many generators to make the bid-mitigation process for out-of-merit generation more mechanical. Also, the NEPOOL Markets

In summary, it appears that as more markets are open to competitive bidding and more extensive mitigation procedures are implemented, market monitoring activities must increase to keep pace.

3.2 Accountability and Independence

The MMUs for PJM, NE, and NY, and the Market Surveillance Unit for CA, are all ultimately accountable to the CEO of their respective ISO and are considered ISO employees. The Market Surveillance Committee, in CA, and the Market Advisors, in NE and NY, are not ISO employees and report to the governing Boards of each ISO. This dual approach appears to be an optimal arrangement for several reasons.

First, having the MMU staffs integrated into the ISO staff structure provides opportunities for informal interactions between the market monitors and the scheduling and dispatch operations at each ISO. As explained by a market monitoring staff person "You can learn much more in a five-minute conversation with a control room operator than you can learn after hours of reviewing print-outs of participant bids and unit commitment reports". This same staff person advocated strongly for "close physical proximity" of market monitoring staff to the scheduling and dispatch functions to allow for frequent and real-time interactions.

Second, having MMU personnel as ISO staff rather than "outside employees" helps lower barriers to communication by allowing all ISO staff to be part of the same team. While some outside observers have concerns that market-monitoring staff will be less vigilant and independent if they are part of the ISO staff, none of the market monitoring staff that we spoke with identified such a concern. It certainly may be appropriate to develop "whistle-blower" protections for ISO market monitoring staff; this would guard against the most egregious forms of management manipulation of market monitoring reports or retaliation for unflattering reports. However, whistle-blower protections are probably needed for all ISO staff, not just market monitoring staff, to ensure the even-handedness, honesty, and independence that are so essential for both market monitors and market administrators.

Third, having an "outside" independent entity reviewing all the market information and reports provides appropriate and useful checks and balances against a dysfunctional MMU (whether due to deliberate concealment or merely incompetent analysis) or an unconcerned ISO management or Board of Directors. Although it appears, to date, that the current ISOs have been quite candid about the problems and failures of their new market systems, it is certainly possible that future managements may become defensive and protective of their market system and be reluctant to identify dysfunctions. An outside independent entity can be very useful if such a scenario develops.

Committee is currently evaluating further changes to MRP 17 to allow for pre-negotiated price agreements for generation units that seldom run in merit, in order to avoid the lengthy after-the-fact settlements.

3.3 Scope of Monitoring and Indices Used

PJM, NE, NY, and CA MMUs are all charged with monitoring all ISO markets and identifying flaws or potential flaws with those markets. Exercises of market power, abuse of rules, and other specific participant behaviors are highlighted. The NY MMU is specifically charged with monitoring the "competitiveness, performance, and economic efficiency" of its markets. The NE MMU is charged with assessing the "competitiveness and efficiency" of its markets and any "aspects that prevent competitive results". The PJM MMU is charged with monitoring "bilateral markets within PJM and regional markets outside of PJM." This last point is worth further discussion. The ability to monitor bilateral contracts, as well as activities outside a particular ISO or RTO boundary, is crucial to understanding the "net" positions of market participants. It may not always be owners of generation resources that can profit from high clearing prices. For example, a load-serving entity that has contracts for resources in excess of its needs will likely be a net-seller in either the day-ahead or real-time market, and, therefore in a position to profit from a high clearing price. In contrast a generator who has contracted to provide more power than its generation units can deliver will likely be a net-buyer in the day-ahead or real-time market, and therefore, in a position to profit from a low clearing price.[40]

Finally, the PJM MMU has the authority to monitor and, with Board approval, intervene in FERC and state proceedings regarding mergers and acquisitions. This is a logical responsibility for an MMU, given its mandate to ensure competitiveness in electricity markets.

The broad scopes of authority granted to MMUs seem appropriate. We did not find any specific enhancements from our review of other MMUs outside the US. However, it is not clear that all the ISOs have been able to structure their activities to meet the broad scope of their general authority. New England and New York have been candid about their inability to implement the comprehensive type of monitoring envisioned in their scopes of authority, in part due to limited staff and resources and in part due to the complexity of developing systems and procedures to do effective monitoring.

Each of the ISOs has developed a variety of indices to use as evaluative tools. Many of them are similar between the ISOs. These include review of concentrations of ownership (HHIs) pool-wide and in specific transmission constrained areas (load pockets); price and cost evaluations using numerous assumptions to simulate a cost-based dispatch; the comparisons of bids and ECPs to fuel-price data; the changes in bid supply curves over time; and changes in generation unit availability as load changes. Appendix C contains even more detailed and specific indices that are used by PJM and CA.

[40] These are two vastly simplified examples to illustrate a point. In the current markets administered by the ISOs, participants often have numerous "positions"; it is the interaction of all these various positions and the potential for exercises of market power that the ISO MMUs must constantly analyze. Access to bilateral contracts within and outside of a particular wholesale market are essential for the MMU staff to see the "whole picture" relative to an individual market participant action.

One evaluative tool that has been particularly beneficial in the UK is the modeling of the dispatch based on marginal cost data provided by the generators. This model is then compared with the bid-based dispatch of the system. While bid-based prices may never actually fall to marginal cost levels, it is extremely useful to compare the differences between the two dispatches as a gauge of the efficiency of the bid-based market. It is also useful to compare the relationship over time (years) as a gauge of overall market competitiveness.

3.4 Data Collection

All FERC approved MMUs have the authority to collect data necessary to perform their market monitoring and evaluation functions. This includes any data collected by their respective ISO and any additional data that the MMU deems necessary. CA requires that data to be collected be published in a "data catalogue" by the ISO and disseminated to market participants.

However, despite this broad authority, none of the ISOs systematically collect marginal cost data from participants on a regular basis. PJM currently collects cost data for generators built prior to July 1996 to support cost capping of bids in local load pockets. New England collects marginal cost data from only those participants who want to negotiate a pre-set bid-price when they are an "out-of-merit" generator due to congestion. New York only collects data from specific generators when requested by the MMU. In California, generators must provide (to CA ISO and FERC) cost data for generation in any month during which the generator submitted a bid that exceeded the proxy price.[41]

Each of the ISOs, except PJM, can penalize participants who fail to provide data upon request. Those penalties can include monetary penalties (CA, NE), restrictions on bids (NE, CA), binding arbitration (NE, NY) and exclusion from the market (CA, NE). PJM is limited to petitioning FERC to enforce its data requests.

3.5 Monitoring Rules and Procedures

The MMUs for PJM, NY, and CA may recommend changes to their market monitoring procedures directly to their governing boards. In addition, NY may recommend changes to its mitigation procedures with the concurrence of the ISO CEO and the Board's Market Performance Committee. The MMU unit in New England can recommend changes after consultation with state regulatory agencies[42] and with NEPOOL approval. All proposed changes would need to be filed and approved by FERC. NE could also invoke its

[41] 95 FERC 61,115, pp. 15-16. In this order FERC directed that the marginal cost of a generator should be determined using its heat rate, emissions, proxy gas price, proxy emissions cost, and an adder for O&M costs.

[42] This reference to state regulatory agencies is in MRP 17. It is there due to the collaborative process used to develop MRP 17, which involved ISO-NE staff, NEPOOL Participants, state utility regulatory staff, and at least one state attorney general's office.

emergency rule-making authority and implement immediate changes, subject to FERC review; however, to date, NE has never utilized that authority to change market monitoring rules and procedures.

3.6 Market Rules Modifications

The MMUs for PJM, NY, and NE, can make recommendations for changes to the market rules to their respective stakeholder committees. Those committees can then approve the changes, or modify them, and file them with FERC.

In PJM, the MMU also has the authority to file proposed changes directly with FERC, if the changes are approved by the Board of Directors. In NY and NE, the MMU unit can file directly with FERC under each ISO's emergency rule-making authority for exigent circumstances. In CA, the MMU or the independent Market Surveillance Committee can recommend changes to the ISO Governing Board for direct action.[43]

3.7 Corrective Actions

There are a variety of mechanisms that exist within current ISOs for responding to identified competitiveness issues in markets. Some of these tools arise in great part as a result of market flaws that the ISO market-monitoring unit identifies, and some of them are directly within the authority of the ISO to implement.

It is important to note that both the PJM and New England ISO's had more expansive corrective authority during their first year of operations. In PJM, all market participants were required to bid at cost for the first year of operation. In New England, the ISO had the authority in the first five months of operation to revise prices that did not result from competitive forces. In rejecting NE's request to extend that temporary authority in the fall of 1999, FERC stated that the time for such corrections was over; according to FERC, the market participants' need for price certainty outweighed the need to continue to revise prices based on flawed market designs. FERC directed ISO-NE to recommend market design changes on a prospective basis through the NEPOOL committee process, or, if necessary, to make immediate changes using its emergency rule-making authority.

Bid caps

As mentioned earlier, PJM has had a $1,000 per MWh bid cap in place since the start of its markets.[44] CA has had a variety of bid caps in both its reserve and energy markets since the early days of its markets. Most recently, CA had a series of "soft" bid caps ordered by FERC for its energy market in response to the months of high energy clearing

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[43] In CA, as originally constituted, the ISO Governing Board was more similar to a stakeholder committee than an independent Board of Directors. FERC recently changed the composition of the Governing Board to reduce the influence of market participants.

[44] Due to the added cost of congestion, prices may exceed $1,000 per MWh even with a bid cap of $1,000.

prices (and rolling blackouts) that CA experienced in late 2000 and early 2001. The current soft cap in CA for all hours is established in relation to the market clearing marginal cost bid during a reserve deficiency event.[45] NE and NY both have a $1,000 bid cap, that was first approved by FERC in July 2000. Pursuant to recent FERC orders these caps will continue at least until implementation of the Northeast RTO.[46]

In addition to the energy markets, the regulation market in PJM has a $100/MWh price cap; the reserve markets in NE are capped at the energy-clearing price during capacity deficiency events, and the non-spinning reserve market in NY is capped at $2.52/MWh (plus an "opportunity cost" adder).

Bid mitigation

ISO-NE and NY ISO are authorized to mitigate bids prior to accepting them. Until recently, ISO-NE had authority to review any bid and to ask the entity submitting the bid to justify it. NYISO has employed bid screens, or thresholds, for determining which bids are eligible for mitigation since the start of its markets. For automatic mitigation, the threshold is a bid that is 300% or higher than a competitive bid and the impact must raise the clearing price by 200% or more. A second tier threshold allows the NYISO to file a proposed mitigation with FERC if the impact of a bid raises the market-clearing price by 100%. Attempts by market participants to lower such thresholds have been vigorously resisted by the NYISO. In July of 2000, FERC ordered ISO-NE to file mitigation thresholds in order to eliminate the excessive "discretion" that ISO-NE had in deciding which bids to review. In response, ISO-NE developed thresholds that are triggered when a bid exceeds a reference price by 300% or $100, whichever is lower, and the impact on market clearing prices is 200% or $100/MWh, whichever is lower. These are essentially the same thresholds used by NYISO.

If bid mitigation is triggered, bids are reduced to default bids generally set at 100% of a reference price.

In California, FERC has permitted generators to submit bids that exceed the market-clearing price; however, those bids are subject to justification and refund. A generator submitting a higher bid must submit a justification to the ISO and FERC, including a detailed accounting of all of its component costs for each hour where the bid exceeded the market-clearing price. FERC may, upon review of the justification, order a refund.[47]

In the UK, a monitoring group has proposed thresholds that trigger mitigation at significantly lower levels. If a supplier has the ability to raise prices by just 5%,

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[45] 95 FERC 61, 148 (June 19, 2001).

[46] For ISO-NE, see 97 FERC 61,090 (October 25, 2001). For NYISO see 97 FERC 61,095 (October 25, 2001).

[47] 95 FERC 61,115 (April 26, 2001).

mitigation would be applied (the 5% threshold is for a total of thirty days worth of hours over a one-year period). The ability to raise prices by 15% (for a total of 10 days of hours over a one-year period) or by 45% (for a total of about three days of hours over a one-year period) would also trigger mitigation. These thresholds are significantly below the 200-300 % thresholds that NYISO uses, although NYISO is looking at single hour increases and not the cumulative impact over a year.[48]

Price corrections

There are differences in authority for price corrections resulting from errors and those resulting from market-design flaws.

With respect to price corrections resulting from software or data entry errors, it appears that NE, NY, and PJM all have the authority and obligation to correct prices under the filed rate doctrine. As FERC stated:

> ...we believe that it is not necessary to extend NYISO's TEP authority in order to facilitate correction of prices calculated on the basis of computational errors. Under the filed rate doctrine, NYISO already has the authority, and is required, to take corrective actions in a timely manner in order to ensure prices consistent with its Commission-approved tariff.[49]

As a matter of current practice, ISO-NE flags, reviews, and corrects prices within specified time frames. During weekday working hours, prices must be flagged for correction within 75 minutes of being posted and corrections must be made within five days. For all other hours (non-work and weekend), prices must be flagged within 24 hours and revisions made within five days.

With respect to price corrections due to market-design flaws, both NE and NY initially had explicit authority to flag, review, and correct prices. FERC subsequently revoked such authority for both ISOs. PJM has never had authority to correct prices for market-design flaws.

3.8 Sanctions and Penalties

ISO-NE, NYISO, and CAISO have authority to impose sanctions for a variety of participant behaviors. In CA the MMU may recommend fines and suspensions and the ISO Board may impose sanctions. ISO-NE, through specific market rule, may impose sanctions and penalties for physical withholding, failure to perform, failure to follow ISO instructions, inaccurate bid information, and failure to provide requested information. NYISO can impose penalties or sanctions for physical withholding, excess generation,

[48] See Appendix B for further discussion.

[49] 97 FERC 61,095 (October 25, 2001).

under-scheduling of load, failure to follow ISO dispatch instructions, and failure to provide requested information.

In determining the level of the sanction, ISO-NE uses a series of formulae that increase with each offense. NYISO calculates a market-based penalty for withholding and over-generation. Under-scheduling of load is penalized by a requirement to schedule all load in the day-ahead market, and a penalty factor added to any real-time purchases.

3.9 Congestion Procedures

PJM, ISO-NE, and NYISO have specific monitoring and mitigation procedures for addressing market power related to congestion. PJM and NYISO have congestion management systems that identify locational prices due to congestion. ISO-NE is in the process of developing a congestion management system. For generating units in load pockets, often called out-of-merit generation, all three ISOs impose some form of bid-cap on those generators.

In PJM, generators can choose among three bid caps: incremental cost plus 10%; a reference price based on when the unit was in-merit; or a negotiated price. ISO-NE and NYISO use a reference price for generators who are often in merit. For units that are seldom in-merit, ISO-NE uses a calculated reference price as a staring point for negotiating a price with each generator. ISO-NE has commented that the process of "negotiating" a price with specific generators is a very time-consuming one.

3.10 Reporting Requirements and Data Release

All the MMUs release bid data on a six-month lag. The names of bidders are replaced with identifiers that are supposed to maintain anonymity while allowing bids to be tracked over time. To date, FERC has supported the six-month lag in releasing bid data. The rationale for trying to keep bids anonymous is that competitors will gain an advantage, and be better able to game the market, if the names of bidders are not obscured. Many people have noted that any market participant with a working knowledge of the regional market and generation units can identify individual bidders with a small degree of additional effort. In general it is non-participants, including the public, who are unable to "decipher the code", not market competitors. Consequently, the bid anonymity does little to enhance the competitiveness of the market, and merely makes the markets less transparent to non-market participants.

The six-month lag, too, is intended as a protection against entities trying to game the market. There are some economists, however, who believe that a one-month lag is probably sufficient to prevent anti-competitive behavior. In UK/Wales and Australia markets, bid data is released publicly with only a one-day time lag.

4. Critical issues and recommendations

4.1 Summary

Despite the wide variety of market monitoring approaches that have been developed and implemented by system operators, our research has identified numerous areas of agreement among the market monitors themselves, as well as other market stakeholders, regarding critical structural and functional requirements for effective monitoring, mitigation, and sanctioning of market-participant behavior. This section identifies those areas of agreement. It also looks at some "best practices"[50] that should be adopted for a Northeast RTO, and notes where they are not incorporated into the market monitoring authorities and practices currently in place in PJM. Many of those recommendations could be incorporated in the short-term into PJM's market monitoring practices, pending the development of the Northeast RTO.

In summary, there are four basic themes for effective market monitoring:

1. The market monitor should be independent and charged with a "public interest" responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

2. The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

3. The market monitor should have authority to mitigate, sanction, and penalize, as well as the authority to identify and implement necessary rule changes.

4. The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

We will discuss each of these in the following sections.

4.2 Independence and Mandate

The market monitor should be independent and charged with a "public interest" responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

Recommendation #1: The MMU must closely monitor, and ideally be physically present or adjacent to, the control room dispatch.

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[50] The term "best practices" has become a much-debated term in the context of developing a Northeast RTO. We use the phrase here in a very broad context to refer to existing practices of the Northeast ISO or other ISO/RTO entities that, in our judgment, should be incorporated into market monitoring activities.

Market monitoring requires constant access to and communication with the operators who are setting day-ahead and hour-ahead power schedules as they respond to dynamic system conditions on a seven-day by twenty-four hour basis. For all practical purposes, this close, daily contact with operations staff necessitates the incorporation of the MMU as a department within the ISO.[51]

Recommendation #2: The MMU should report within the RTO to the Board of Directors. The MMU should work closely and collaboratively with the CEO and the RTO staff that has market design responsibilities.

There should be clear and specific procedures to encourage MMU staff to provide current and accurate information on market conditions and behaviors and to protect the staff from any retaliatory actions by management (whistle-blower protection). Of course, the effectiveness of market monitoring, and the potential for addressing identified market competitiveness concerns, will be significantly affected by the institutional arrangements within which the market monitor and its parent organization operate. For example, where market participants have a mechanism for delaying or preventing market rule changes recommended by the market monitor, the effectiveness of the market monitor in ensuring the competitiveness of markets is hampered. On a day-to-day basis, the MMU should function within the RTO as staff and be subject to the direction of the CEO. However, to help ensure the independence of the MMU, its budget and personnel decisions should be under the direct control of the Board of Directors.

Recommendation #3: The RTO should contract with an Independent Market Monitor (IMM) or Market Advisor to complement and advise an internal MMU. The IMM should report directly to the Board of Directors of the RTO.

The IMM, in consultation with the Market Monitoring Unit, should comment on the overall efficiency of the markets and suggest long-term improvements. The day-to-day market monitoring, rules changes, and periodic reporting should reside with the internal RTO MMU. The IMM can also provide a valuable “second opinion” to the RTO Board on market-design issues and proposed rule changes. For that reason, the IMM should report directly to the Board of Directors and stand outside of the RTO organizational structure that reports to the CEO.

4.3 Comprehensive Scope for Monitoring

The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

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[51] In the context of a Northeast RTO, it may be appropriate to have satellite MMUs at each control area with a central MMU office at the RTO to coordinate inter-control area monitoring and changes to Northeast RTO market rules and procedures. Even under this scenario, the MMU staff at the control areas may perform best as employees of the same entity that employs the operations staff.

Recommendation # 4: The MMU should be responsible for monitoring all wholesale markets administered or facilitated by the RTO/ISO, including the spot and bilateral energy, ancillary-services, capacity, and transmission markets. The MMU should monitor both supply and load bids in all markets.

Other related markets should be monitored (fuel, emissions, and derivative markets) due to their dynamic interaction with, and impact upon, electricity markets. The MMU should, on a routine basis, collect information on bilateral contracts among participants and monitor electricity options markets as they develop. Monitoring should occur in all hours, and account for different market conditions, including congestion, excess generation, low operating reserves, and system emergencies.

There may be additional markets developed and administered by the RTO (such as a resource-attributes market to facilitate compliance with various state regulatory requirements regarding disclosure, renewable resources, and emissions standards) that will require monitoring and evaluation to ensure competitiveness and efficiency. [52] The MMU should monitor and evaluate all markets based on the opportunities to trade in those markets. Thus, as in PJM today, the MMU would look at both day-ahead and real-time markets. If a four-hour-ahead or hour-ahead market is implemented, this should be monitored also.

Comprehensive market monitoring includes technically challenging and time intensive activities. The MMU must be staffed and budgeted at adequate levels to accomplish all of these functions.

Recommendation #5: As part of its ongoing evaluation of market efficiency and competitiveness, the MMU should evaluate the performance of the markets against the outcome of a market where all bids are at marginal cost.

Bids above marginal cost should be evaluated for their impact on the efficiency of the markets.[53] In evaluating the overall performance of the market, the MMU should compare bids with marginal costs, and determine whether and to what extent actual market prices deviate from competitive outcomes.[54] For this analysis, a model based on

[52] For example, many of the states in the Northeast RTO require retail load serving entities to provide periodic reports to customers on the fuel-mix of the generation resources purchased for those customers. A few of the states also require minimum percentages of renewable generation resources be purchased for each retail customer. A single regional accounting system for the Northeast market that assigns generation resources to specific load accounts, based on systems already being developed in New York, New England, and PJM, is the simplest and most efficient approach. As New York and New England have already determined, any such system will need to be monitored to ensure that potential gaming and anti-competitive activities are addressed.

[53] Where a distinct ISO capacity market exists, energy supply bids in an efficient market should resemble short run marginal operating costs. In California and other ISOs without a capacity market, energy supply bids may be higher than short run marginal operating costs reflecting recovery of fixed costs.

[54] We are not, however, recommending a specific "standard" for quantitatively determining whether a particular market is "workably competitive."

marginal-cost bidding is an important analytical tool. While we would not expect actual prices to precisely follow a cost-based model, a cost-based model provides critical information regarding the extent to which actual prices diverge from those would be expected in a truly competitive market with marginal-cost bidding.

Recommendation #6: The MMU should have the authority to assess the impact on the market of proposed mergers and acquisitions, and be a party to such proceedings.

Mergers and acquisitions can have significant impacts on market concentration and the potential for market power to be exercised. The market monitoring plan should provide the MMU explicit authority to participate in merger and acquisition proceedings and provide an assessment of the likely market impacts of the proposed consolidations.

4.4 Authority to Act

The market monitor should have authority to mitigate, sanction, and penalize, as well as the ability to identify necessary rule changes.

Recommendation #7: The MMU should have access to all data that will assist it in performing its market monitoring function.

In addition to all the bids submitted into the market place, the MMU should have access to all operational and systems data collected or generated by other RTO staff and market participants.

The MMU should also have authority to collect marginal cost data and operator logs from market participants. The former data would be used to support the assessment of market performance on the basis of marginal-cost bids, as discussed above. Operation logs would support the MMU's investigation of possible market manipulation through physical withholding.

Recommendation #8: The MMU should have authority to mitigate any bid in any market prior to accepting it.

While thresholds for mitigation may provide useful guidelines for the MMU, they should not limit the MMU's authority to review bids below the thresholds at its discretion. The MMU should have the authority to review bids and take specific appropriate action, subject to appeal to FERC.

Recommendation #9: Bid caps should be used as an essential component of electricity markets.

As FERC has recognized, bid caps have an essential role in securing just and reasonable electricity market prices. In a recent order on California market monitoring, FERC justified the need for bid caps as follows:

> Because of the lack of demand response, these prices may not reflect what the market would have established as appropriate scarcity rents and, therefore, may not be just and reasonable.[55]

Bid caps and bid mitigation should both be used. Although uniform bid caps provide a critical restraint on overall market prices in a small number of high-priced hours, they are not an adequate substitute for generator-specific bid mitigation which addresses potential market power in all hours and under all market conditions. At the same time, bid mitigation procedures, as currently implemented, do not appropriately restrain anti-competitive bidding.

Demand response programs are also not an adequate substitute for bid caps at this time. All current bid-based market structures have difficulty functioning when demand approaches or exceeds available supply, and load response should be developed to address this.[56] However, even under the most optimistic and ambitious scenarios for demand involvement in electricity markets, the point at which demand response will be adequate to restrain anti-competitive supply behavior is at least a decade away.

Recommendation #10: In addition to its authority to mitigate a bid in advance of accepting it, the MMU should also have the authority to impose sanctions or penalties on market participants for specific behaviors, including the failure to provide information requested by the MMU.

The behaviors listed in NEPOOL's MRP 13 are a good initial list;[57] however, the MMU should have the responsibility to identify other anti-competitive or gaming behavior and make them subject to sanctions too. The magnitude of penalties and sanctions should be sufficient to at least offset potential gains from anti-competitive behavior.

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[55] 95 FERC 61,115 (April 26, 2001).

[56] In this regard, RTOs should implement procedures that allow load to bid into the market in the same fashion as generators. For example, market rules could permit load to bid in advance a price at which a specific amount of megawatts could be reduced. Such bids could be treated as generation resource in the daily dispatch bid-stack. Market rules could also allow load to respond, in real-time, to market clearing prices as a price-taker. These approaches should not be limited to large consumers, but should accommodate small loads, including residential loads, that could be aggregated by market brokers. In addition to qualifying for energy market compensation, load responsiveness should also be able to qualify for installed capacity payments and reserve payments to the extent that they qualify. Traditional state and utility sponsored energy efficiency programs should also be able to receive compensation for peak load reductions. As with supply bids, load bids and demand response programs will need to be monitored to ensure that anti-competitive practices can be identified and curtailed.

[57] MRP 13 includes sanctions for following behaviors, if not excused: failure to provide energy, failure to provide services, failure to respond to dispatch instructions, failure to perform in markets, inaccurate bid or operating information, failure to follow scheduling procedures, failure to follow transmission instructions, failure to provide information, and failure to comply with market mitigation rule.

Recommendation #11: The MMU should have the authority to flag clearing prices and make price corrections for a limited period of time after the market clears.

As noted in Section 3.7 above, ISOs have the authority and responsibility to correct prices for errors. However, this authority does not extend to corrections for market-design flaws. Although initially ISO-NE and NY had authority to correct prices for market-design flaws, FERC subsequently revoked it.

The issue of whether to allow price corrections for market design flaws is controversial. In considering whether to allow price corrections for market-design flaws, a key issue is how to balance the market's need for accurate prices with its need for certainty of prices. Ideally, at the end of each day market participants need to know where they stand, i.e., at what price and quantity did they buy or sell electricity. On the other hand, market participants need to have confidence that the systems for establishing prices for sales and purchases produce technically accurate results consistent with a competitive market, i.e., are not subject to manipulation or gaming. Striking an appropriate balance between these competing concerns has been a difficult and on-going challenge for the ISOs and FERC.

We conclude that providing a limited time period for correcting prices for market-design flaws is a reasonable compromise.[58] ISO-NE's 75-minute window during business hours (24 hours for non-business hours and weekends) for flagging a price for review is a reasonable approach.[59] If a price is flagged, market participants are on notice that the price may be revised and can make their forward going decisions accordingly. A five-day period for making revisions after a price is flagged seems to be a reasonable amount of time to complete an initial review. As experienced is gained, the authority to correct prices could be curtailed or eventually eliminated.

Recommendation #12: The MMU should have the authority to file with FERC for changes to both market-monitoring rules and market rules.

There should be a standard process for filing changes (which may include review by stakeholders and the concurrence of the RTO Board). The MMU should also have emergency authority to file changes that go into effect immediately, but are subject to FERC review within 60 days.[60]

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[58] The Pennsylvania Office of Consumer Advocate supports market monitoring authority to make after the fact price corrections for computational errors only. However, the Pa. OCA disagrees that the market monitor should make after the fact price or bid changes to remedy market design flaws or other market abuses. The Pa OCA supports the use of other tools to remedy such flaws and abuses, including filings to change market rules and market design, bid caps, before the fact mitigation of bids, FERC investigations and refunds, sanctions and penalties.

[59] These are the requirements in ISO-NE's MRP 15.

[60] ISO-NE's emergency authority under Section 6.17 of the Interim ISO Agreement is a good model.

Finally, it is critical that the MMU be able to respond to new market behaviors in a dynamic fashion. Market participants are continually striving, as any profit-making entity should, to determine profit-making behaviors that are allowed within established market rules. The MMU must not be overly restricted in its ability to respond to the continuous innovations in market behavior by restrictions on the hours or circumstances under which it can monitor the markets and participant behavior. Competitive electricity markets are still relatively new and are undergoing constant change and evolution. The market monitor cannot be given a static and inflexible tool kit with which to ensure the competitiveness of fluid and evolving markets.

4.5 Data Access and Reporting

The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

Recommendation #13: In order to improve transparency and enhance confidence in the markets, the MMU should regularly and frequently issue detailed reports on its monitoring activities.

The MMU, as part of an overall effort, should strive to maximize the transparency of its own actions and the transparency of the markets in general. Absent compelling reasons that specific information will harm the competitiveness and efficiency of the markets, reports on market activities should be posted on the ISO or RTO website. For information that is too sensitive for public release, redacted versions should be provided for posting on the ISO or RTO website. Non-redacted reports, with appropriate confidentiality protection, should be provided to the ISO or RTO Board, FERC, and state jurisdictional entities including state consumer advocate offices.

The type and frequency of reports should be similar to those currently provided pursuant to MRP 17 for the New England wholesale markets.[61] For example, a market monitoring unit should prepare a monthly report that describes activities in each market, compares prices to other markets and previous months, and describes any regulatory actions or rule changes that have occurred. The market monitoring unit should also prepare a quarterly report for regulatory agencies that summarizes the three monthly reports, compares bids and prices to previous quarters, identifies any mitigations and sanctions taken, and an assessment of market efficiency. Finally, the market monitoring units should prepare an annual report that assesses annual market performance against a marginal cost dispatch, assesses the overall competitiveness and efficiency of each market, and describes changes and improvements that were implemented in the reporting year, as well as future refinements to the markets. The annual report should be presented and discussed at an annual forum that is open to the public.

Recommendation #14: Bid data with names should be released on a one-month lag.

[61] FERC has praised the monthly and quarterly reports produced by ISO New England for their thoroughness, detailed charts, and comparisons to other wholesale markets.

The ISOs currently release bid data on a six-month lag basis and coded to allow tracking of bids without revealing the bidders' names. As a practical matter, coded names are not a barrier to market participants who, with a minimum of effort, can reliably identify the specific bidders. The coded names are an obstacle to non-market participants such as regulatory agencies and the general public who seek to develop a better understanding of participant activities. Therefore, we recommend the release of bid data with the bidders names.

One of the principal reasons to publish bid data is to allow other market participants, regulatory agencies, and the public at large to evaluate the data and comment upon it. Load serving entities, in particular, have a strong interest in uncovering inappropriate bidding activities that raise prices; they are paying those prices to serve their customers. A six-month lag is problematic for two reasons. First, it allows too long a period for gaming activities to go on without detection or correction. Second, it makes detection and correction more difficult due to the long time between an event (such as the $1,000 ECPs in New England this summer) and the opportunity to analyze the bid data that created the event (Summer 2001 data will not be available until January 2002 at the earliest.

There have been proposals to shorten the reporting time from six-months to three-months; a few people have suggested releasing bid data after 24 hours. We are concerned that a 24-hour lag would provide too much detailed information regarding bidding strategies and encourage short-term gaming efforts. However, we believe that the dynamics of the wholesale markets could support a one-month lag of bid data. Bidding strategies are subject to frequent revision based on the changing circumstances of individual participants (for generators this includes outages and other variations to their generating capacity; for load serving entities this includes changes to their customer base) and the market in general (the combined effect of thousands of individual participant factors). Such a dynamic process is likely to diminish the value of one-month old bid information to those entities that would try to manipulate the market based on such information.

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Appendix A
Comparison Tables:
Market Monitoring in PJM, New York, New England, and California

Table A1: Size and Budget of Market Monitoring Entity

	PJM	NY	New England	CAL ISO
Staff	5 employees	11 employees in 2000; budgeted to increase to 23 employees in 2001 (2001 Business Plan, at 19).	Current staff of 8; when two open positions are filled there will be 10.	MSC: 3 or more independent experts (MMIP 5.2.1).
Total annual budget	NA	NA	NA	MSC: Compensated as established by ISO Governing Board (MMIP 5.4).
Authority to hire outside expertise	Yes, subject to oversight by President and/or Board (MMP V.B).	Yes, in consultation with Market Advisor and subject to oversight by CEO (MMP 3.2).	Yes, with approval of CEO and Board of Directors.	MSU may hire consulting assistance (budget approved by ISO CEO) and seek external expert advice (MMIP 4.6).

Table A2: Institutional Arrangements

	PJM	NY	New England	CAL ISO
ISO Market Monitoring Entity	Market Monitoring Unit staffed by PJM employees, accountable to President and PJM Board (MMP V.B, V.C).	Market Monitoring Unit staffed by NYISO employees, accountable to CEO (MMP 3.2, 3.3).	Market Monitoring & Mitigation Unit staffed by ISO-NE employees, accountable to CEO and NEPOOL (IIA 6.4)	Market Surveillance Unit under management of ISO Chief Legal Counsel and ISO CEO (MMIP 3.2, MMIP 3.3.1).
Independent Market Monitoring Entity	None.	Market Advisor accountable to the CEO and serving at the pleasure of the Board (MMP 4.1). Market Advisor advises and reports directly to the Board (MMP 4.3).	Independent Market Advisor who assists Board of Directors and MMM group (Press Release 5-23-01).	Market Surveillance Committee (MSC). An independent advisory committee made up of 3 or more independent experts -not ISO staff - (MMIP 5.1, MMIP 5.2). MSC advises ISO CEO and ISO Governing Board (MMIP 5.1) and may refer matters directly to ISO Governing Board (MMIP 3.3.2).

Table A3: Scope of Market Monitoring and Indices Used

	PJM	NY	New England	CAL ISO
Practices subject to scrutiny	MMU responsible for monitoring (1) compliance with all rules, standards, and procedures; (2) actual or potential market-design flaws; (3) ability of market participants to exercise market power (MMP III).	MMU responsible for monitoring (1) competitiveness, performance, economic efficiency of electric markets; (2) market-participant conduct; (3) operation and use of transmission system as it effects competitiveness and efficiency; (4) adequacy and effectiveness of tariffs, rules, standards, procedures, mitigation or other remedial measures (MMP 1.1).	MMMG has authority to independently assess the competitiveness and efficiency of the NE markets including physical withholding, bid mitigation, economic withholding, price anomalies, flaws in market design or software, and other aspects that prevent competitive results (MRP 17.1).	Anomalous market behavior, abuse of reliability must-run unit status, gaming, ISO and PX design flaws, market structure flaws (MMIP 2.1).
Markets / products monitored	MMU authorized to monitor all markets administered by ISO, bilateral markets within PJM, and regional markets outside of PJM (MMP I).	MMU authorized to monitor all markets administered by ISO or involving ISO-provided transmission services, and regional markets outside NY (MMP 5.1.2).	MMMG authorized to monitor any aspect of the New England markets (MRP 17.1). IMA authorized to advise on how to improve wholesale markets.	MSU monitors ISO markets and coordinates with PX. (MMIP 2.1).

Authority to select indices	MMU develops and publishes variety of indices used to evaluate collected data (MMP VI.E).	Upon approval of the CEO, and at its discretion the Board, MMU develops and publishes variety of indices used to evaluate collected data (MMP 7.1).	MMMG develops and publishes variety of indices used to evaluate markets.	MSU develop and refine catalog of market monitoring indices (MMIP 4.1.3).
Public review of indices used	MMU required to provide opportunity for stakeholder comment on proposed indices (MMP VI.E).	MMU to give "due consideration" to proposals and comments of stakeholders regarding indices (MMP 7.1, 7.2).	Included in Annual Market Review and part of annual public forum (MRP 17.6.2.3).	Indices are available on the CA ISO website.

Table A4: Data Collection

	PJM	NY	New England	CAL ISO
Authority	MMU has access to all data gathered or generated by ISO during course of normal business operations (MMP VI.A). MMU also authorized to request additional data from market participants (MMP VI.B).	MMU has access to all data gathered or generated by ISO during course of normal business operations (MMP 6.1). MMU also authorized to request additional data from market participants (MMP 6.2).	MMMG has access to any and all data that ISO-NE deems necessary, including cost data from generators (MRP 17.6.1).	MSU develop and refine catalog of data to collect, and procedures to handle data (MMIP 4.1.2). MSC full discretion to specify data types and evaluation criteria (MMIP 6.1). ISO CEO must institute data collection, organization and analytic activities to support MSU (MMIP 3.3.3.2). Data catalog published and disseminated to Participants (MMIP 8.1).
Generator cost data collected	Systematically for all generators on-line prior to July, 1996 (OA, Schedule 1, 6.4; OA, Schedule 2).	No systematic collection. MMU may request specific data from individual generators (MMP, 6.2.1).	Only for generators that seek to negotiate a bid-price with ISO-NE due to congestion.	Generators who submit a bid that exceeds that market-clearing price must submit cost data to ISO and FERC (95 FERC 61,115, p. 15-6).
Enforcement ability	No direct enforcement authority. MMU can petition FERC to	Market participants required to promptly provide data requested	Interim ISO Agreement states that NEPOOL Participants "shall	ISO may impose penalties or sanctions for ISO Participant's failure

	enforce requests. (EDR, at 10).	by MMU, and to submit to binding arbitration in the event that MMU determines that the requested data will not be provided within a reasonable time (MMP 6.2.2).	provide the ISO with any and all information . . . that the ISO deems necessary" (IIA 7.2). Also, MRP 13 provides sanctions for failure to respond to data requests.	to provide information, including exclusion from market (MMIP 4.5.2). MSU may report failure of other entities (e.g. PX) to ISO CEO and Governing Board or to pertinent regulatory agency (MMIP 4.5.1).
Requests for data collected by Market Monitoring entity	No provision.	Upon request, MMU may publicly release data if such data is not confidential and release of such data would not be overly burdensome (MMP 6.4(e)).	Data may be released subject to the confidentiality limitations of the NEPOOL Information Policy (MRP 17.6.1).	ISO CEO has sole discretion whether to provide data it has collected to Participant who requests it (MMIP 4.5.3).

Table A5: Changing Market Monitoring Rules

	PJM	NY	New England	CAL ISO
Authority to change market monitoring rules	MMU may recommend to the PJM Board changes in the MMU or MMP (MMP VII.A)	Market Advisor and MMU may recommend changes to the MMU or MMP as part of its annual report to the Board (MMP 10.1). In addition, Market Advisor and MMU, with approval from CEO and Board's Market Performance Committee, authorized to recommend revisions to existing mitigation measures (MMP 8.2)	MMMG can propose changes to monitoring and mitigation rules for filing with FERC, in consultation with regulatory agencies and NEPOOL, or by ISO-NE in emergencies (MRP 17.1.3 and 17.5)	MSU may recommend to the ISO Governing Board changes to its rules and protocols (MMIP 2.3.2)

Table A6: Changing Market Rules

	PJM	NY	New England	CAL ISO
Market monitor authority to market rules	MMU may recommend changes to stakeholder committees or, with Board approval, file for changes directly with FERC (MMP IV.A)	MMU may recommend changes to stakeholder committees, CEO, or Board (MMP, 11.1(d)). Board may file for changes without committee concurrence only to address exigent circumstances. (ISO Agreement, Article 19)	MMMG reports to VP of Markets Development who can propose market rules changes for NEPOOL consideration, or on its own subject to 6.17 of the IIA (IIA 6.4 and MRP 17)	MSU may recommend changes to rules and protocols of PX, ISO markets, PX markets (MMIP 2.3.2)

Table A7: Bids Caps, Bid Mitigation and Market Price Changes

	PJM	NY	New England	CAL ISO
Bid caps	\$1,000/MWh cap on energy bids (OA, Sched 1, 1.10.1A). \$100/MWh cap on regulation bids (OA, Sched 1, 1.10.1A). During first year of markets, all generators required to bid at cost.	\$1,000/MWh cap on energy bids (Services Tariff, Attachment F). \$2.52/MWh plus opportunity cost on bids for non-spinning reserve (FERC order, 11/8/00.)	\$1,000/MWh cap on energy bids; reserve prices not to exceed energy price (FERC Order, 10/25/01)	FERC has instituted a soft bid caps, based on proxy marginal costs, for periods of capacity shortage as well as non-shortage hours (95 FERC 61,115,s issues April 26, 2001 and 95 FERC 61,418, June 19, 2001)
Bid-mitigation authority	None, other than in local load pockets.	MMU authorized to mitigate supply bids in day-ahead and real-time energy and reserve markets (MST, Attachment H, Section 4).	MMMG authorized to mitigate Participants' bids and unit characteristics subject to specific thresholds (MRP 17.2).	NA
Bid-mitigation practices	NA	Bid-mitigation triggered only when suspect bid exceeds reference level by threshold amount and only if bid-mitigation would reduce LBMP by threshold amount (MST, Attachment H, 3.1-3.2).	Thresholds for bid-mitigation are specified in reference price screens (17.2.2.1), investigation thresholds (17.2.2.2), and Hourly Market Impact and Uplift Thresholds	NA

		In addition, MMU can file with FERC for mitigation authority in the event that bid has material effect on market prices, but does not exceed standard mitigation thresholds. (MST, Attachment H, 3.2.3).	(17.2.3).	
Corrective actions	MMU authorized to issue demand letters to market participants to cease actions found to be in violation of rules, standards, or procedures (MMP IV.A).	If bid triggers mitigation, MMU authorized to substitute "default bid" based on previous unmitigated bids (OA, Attachment H, 4.2). For day-ahead market, default bid substituted prior to setting, and used to set, LBMP. Default bid applies for six months. (MST, Attachment H, 4.6) In addition, MMU authorized to engage in discussions with, or issue demand letters to, market participants to	MMMG may substitute a default bid that is 100% of the Reference price determined through 17.2.2.1 (17.2.4).	FERC may order refunds upon reviewing justification of bids that exceed the market-clearing price (95 FERC 61,115; 95 FERC 61,418).

		correct actions found to be in violation of rules, standards, or procedures. (MMP, 11.1).		
Authority to Change Market Prices	Can revise prices due to computational errors.	Can revise prices due to computational errors.	Limited ability to change market prices based on human or software error, or due to extreme system emergency (MRP 15) MRP 15 allowed revisions for prices that did not result from a competitive market for first 90 days of new markets. Extended for 60 days; additional extension denied by FERC.	
Practices for Changing Market Prices	NA	NA	Prices must be flagged within 75 minutes to 24 hours and corrections must be made within five days (MRP 15).	

Table A8: Sanctions

	PJM	NY	ISO NE	CAL ISO
Authority	No direct authority.	Authorized to impose penalties or sanctions for occurrences of physical withholding, generation in excess of dispatch signal, or under-scheduling load in day-ahead market (MST, Attachment H, 4.3, 4.4).	Authorized to impose sanctions for a variety of behaviors including physical withholding, failure to perform or follow ISO instructions, inaccurate bid information, and failure to provide information (MRP 13 & 13A).	MSU may recommend actions, including fines and suspensions, against specific entities (MMIP 2.3.2) ISO Governing Board, acting upon recommendation of MSU or MSC, and after audit by MSU, may impose sanctions within its authority, or may recommend sanctions to regulatory agency (MMIP 7.3).
Practices	NA	For physical withholding or over-generation, penalty set at product of amount withheld (or over-generation) and real-time LBMP (MST, Attachment H, 4.3). For load under-scheduling, requirement	Administrative and formula based sanctions for specific behaviors (MRP 13A).	

		to schedule all expected load in day-ahead market, and penalty for purchasing in real-time market in excess of specified allowance level (MST, Attachment H, 4.4).		
Market Participant Recourse			Participant may seek ADR review of any sanctions. Decision from ADR process may be appealed to FERC by participant or ISO-NE. MRP 13.	MSU may institute ADR to resolve differences with market participants over interpretation of behavior and appropriate remedies. (MMIP 2.3.3)

Table A9: Congestion and Load Pockets

	PJM	NY	New England	CAL ISO
Authority	Authority to cap bids of units within load pocket required to be dispatched out of merit for reliability purposes (OA, Sched 1, 6.1). Exception for units relied on to relieve Western, Eastern, Central reactive limits, or other constraints exempted by FERC (OA, Sched 1, 6.4.1(d)).	Authority to cap: 1. Energy bids of units within NYC load pocket whenever (1) transmission constraints limit imports of generation into NYC; or (2) units required to be committed or run out of merit for local reliability purposes. (ConEd Rate Schedule No. 199, Section B [As modified pursuant to 7/20/01 FERC order]). 2. Bids into, and prices received from, NYC installed capacity market (ConEd Rate Schedule No. 199,	Authority to cap bid prices at a reference price for generators in congested areas (defined as less than three competitors). Authority to cap bid prices at a predetermined level (based on cost data) for generation units that are seldom selected, except due to congestion.	

		Section C). 3. Spinning-reserve bids for units committed to meet local spinning-reserve requirements (ConEd Rate Schedule No. 199, Section D).		
Eligibility	All generating units built prior to July, 1996 subject to mitigation. (OA, Sched 1, 6.1)	All generating units located within NYC subject to energy bid cap. ICAP and spinning-reserve caps applicable only to generating units divested by ConEd (ConEd Rate Schedule No. 199, Section A).	Generation units selected as out-of-merit generators.	
Markets subject to mitigation	Restricted to day-ahead energy market (OA, Sched 1, 6.4.1). PJM recently requested authority to apply on real-time basis (6/29/01 filing letter).	Applicable to day-ahead and real-time energy markets, installed capacity market, and spinning-reserve market (ConEd Rate Schedule No. 199).	All markets.	
Bid cap	As elected by generator, bid mitigated to either	In day-ahead energy market, bids mitigated to	Mitigated to reference price (formula based) for	

	(1) incremental cost + 10%; (2) average of LMP at generator bus during hours when unit dispatched in merit order; or (3) amount negotiated with generator (OA, Sched 1, 6.4.2)	"reference price" based on previous unmitigated bids. In real-time energy market, bids set at 10% above reference price. (ConEd Rate Schedule No. 199, Sections B.1, B.2). In installed-capacity market, divested generators' bids and prices received capped at $105/kW-yr (ConEd Rate Schedule No. 199, Section C). In addition, divested generators required to bid all capacity into NYC installed-capacity auction. In spinning-reserve market, divested generators' spinning-reserve availability bids capped at $0 (ConEd Rate Schedule No. 199, Section D).	generators who are often selected in-merit. For generators seldom selected in-merit, a reference price or a negotiated price is used New rules regarding "net commitment period costs", or npcp, provide a method for calculating uplift payments.	

Table A10: Data Reporting and Release

	PJM	NY	New England	CAL ISO
Reporting within ISO	MMU provides periodic reports to the PJM Board (MMP VII.A).	Market advisor and MMU provides reports to the Board on an annual basis (MMP, 10.1) Reports also provided periodically upon request of Board, CEO, FERC, or NY PSC (MMP, 10.2)	Monthly reports to CEO and Board (internal).	MSU must report to ISO CEO and MSC not less than quarterly, and to ISO Board not less than annually, and as needed (MMIP 4.4.1) Director of Department of Market Analysis reports to Governing Board monthly (website) MSU may report directly to MSC (MMIP 4.4.3) MSC must report on its evaluations and recommendations to ISO CEO and Governing Board (MMIP 6.3.1) MSC may require ISO CEO to publish or include MSC reports/findings (MMIP6.4).

Reporting to FERC	MMU provides FERC with all reports to the PJM Board, or any other report requested by FERC (MMP VII.B)	MMU provides FERC with all reports to the Board, or any other report requested by FERC.	All reports to FERC.	MSU reports to FERC annually, reports approved by ISO CEO (MMIP 8.3) MSC may report to FERC (MMIP 6.3.1) Recently FERC has required weekly reports of schedule, outage, and bid data, with identification of bidding behavior issues (95 FERC 61,115, p. 18).

Appendix B
International Approaches to Competitive Markets

England and Wales[62]

The electricity industry was first privatized in 1990 and the Electricity Pool was set up. It was operated under a commercial arrangement: the Pooling and Settlement Agreement, between the generators and the retailers. The pool "was used to determine which generating assets were called on to satisfy demand. The wholesale electricity price was set on a half-hour basis by the most expensive generator used during that period, with all generators receiving that 'marginal' price."[63] There were only two major generators (National Power, now Innogy, and Powergen) at that point, creating a strong potential for the exercise of market power. The main response of the regulator was to force plant sales and divesture. The government also imposed a cap on the pool price.

A new system was set up this year, the New Electricity Trading Arrangements (NETA). It encourages a move towards bilateral contracts signed between generators and retailers and large customers. In addition, five power exchanges have been set up or are in the process of being created. The UK Power Exchange (UKPX) spot market, which started on March 25, 2001, is a 24-hour seven-day market. The owner and operator of the transmission system, National Grid Co. (NGC), a publicly-traded company, "accepts offers and bids from 3 ½ hours ahead of real time, up to real time".[64] This balance and settlement mechanism is managed by Elexon, a non-profit, uncontrolled subsidiary of NGC.[65] This new system seems to have led to a reduction in prices: according to an OFGEM news release in August 2001, "wholesale electricity prices are 20-25 per cent below prices that would have been produced under the Pool" (i.e. the previous system).[66]

The main regulatory agency is Ofgem, the Office of the Gas and Electricity Markets.[67] Ofgem was formed in early 1999, combining formerly separated gas and electricity activities. In terms of market monitoring, Ofgem is charged with overseeing competition of licensees (the market participants) and to refer anti-competitive practices to UK's Competition Commission. Ofgem's Director General (the Director Generator of

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[62] Scotland has a similar framework but there are only two vertically integrated electricity companies. Northern Ireland does not yet have an open market. IEA (2001).

[63] Levesque (2001).

[64] Levesque (2001).

[65] www.elexon.co.uk

[66] "Reviews address NETA's performance and its impact on smaller generators", OFGEM News Release, August 31, 2001 (PN 38). Available at http://www.ofgem.gov.uk.

[67] See www.ofgem.gov.uk

Electricity Supply, DGES) is appointed for 5 years and this mandate can be renewed once. As of March 1997, Ofgem had 233 staff and its running costs for the fiscal year finishing March 1997 were 13 million pounds (UK).[68]

Bower points out, quoting a 1998 report by the electricity regulator, that "[i]n the England and Wales market, strategic capacity withdrawal, especially of marginal plant, has been a major regulatory problem and Ofgem has over the years launched a number of investigations into this kind of behavior by the largest fossil fuel generators PowerGen and National Power".[69] Ofgem has also recently ordered that firms wishing to close plants have to demonstrate that it was uneconomic to operate the latter at the existing market prices. This requirement is likely to lead to spare capacity being put up for sale to competitors.

UK's Competition Commission is the current public independent body, created in 1998, dealing with mergers, abuse of dominant position and other anti-competitive behaviors.[70] Ofgem has been in disagreement with the Competition Commission on the extent of its market monitoring capacity. The Ofgem intended to introduce a so-called Market Abuse Condition in the licenses of generators "capable of exercising substantial market power".[71] Two generators (out of eight major ones that had been identified) refused the inclusion of the Market Abuse Condition in their license and were referred by Ofgem to the Competition Commission. The Commission found in favor of the two generators and Ofgem had to withdraw the Condition from all the operating licenses where it had been included.

It is worth giving some details on this condition, since Ofgem still pushes for it: Ofgem "has managed to get the Department of Trade and Industry to look at its case again, with a view to getting the [condition] reinstated under the 'Secretary of State's special Neta Power', provided by the Utilities Act".[72]

The term substantial market power was defined in the initial Ofgem guideline as "the ability to bring about, independently of any changes in market demand, a substantial change in wholesale electricity prices".[73] The Competition Commission warned that "[M]ore than one license-holder or interconnected group of license-holders may simultaneously have, and exercize, substantial market power in the Pool".[74] The

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[68] IEA (2001).

[69] Bower et al. (2001), p. 1004.

[70] See UK's competition web site at http://www.competition-commission.org.uk/

[71] UK's Competition Commission (2001), p. 88. This reference is not yet included in the list of References.

[72] "Return of the MALC", http://www.energy-directory.com, August 2001.

[73] *The market abuse licence condition for generators. A decision document*. OFGEM, April 2000.

[74] UK's Competition Commission, 2001, p. 89.

precision with which the criteria for potential market power were defined is interesting. The Ofgem guidelines stated that market power could occur through very large effects on prices which occur over a short period of time, or through a series of lesser effects on prices that occur over a longer period of time. The document stated that a license-holder had the ability to exercise substantial changes in wholesale prices if it has the ability to bring about a change of:

(i) 5 % or more for a duration of more than 30 days in a one-year period;

(ii) 15 % over ten days in a one-year period, or

(iii) 45 % over 160 half-hours (a little less than 1 % of the year) in a one-year period.

These do not have to be considered continuous periods.

The DGES would have a duty to take enforcement action (except in certain specified circumstances when the Competition Act would be the most appropriate way to proceed).[75] Ofgem could ask further information from the generators to come up with its initial findings and provisional orders. After a period for comments by the license-holder at each stage of the investigation, Ofgem would be entitled to issue an order. The penalties could amount up to 10 % of the license-holder's turnover. An Advisory Board of five members would be formed to advise on Market Abuse Conditions matters. If the DGES disregarded the opinion of the Advisory Board, the enforcement order may be subject to a legal challenge – thus ensuring a way of appeal.

It will be worth analyzing how much of these provisions might disappear in the new version of the Market Abuse Condition.

Nord Pool **(Norway, Sweden, Finland and Denmark)**

The Nordic Power Exchange, or Nord Pool, is "the world's only multinational exchange for trading electric power".[76] It was created in 1993, initially in Norway, and is owned by the two national grid companies, Stattnett SF in Norway and Affärsverket Svenska Krafnät in Sweden. Since 1990, the four Nordic nations (Norway, Sweden, Finland and Denmark) operate in a joint, competitive wholesale market. This is only a power exchange market and the two grids remain owned by the national companies. There is regulated third-party access to the consumers and all consumers may choose their suppliers (except in Denmark, where consumer choice is planned to begin in 2003). Transmission is owned in each country by an independent, usually publicly-owned company (in Finland, there are some private stakeholders in it); there is accounting unbundling of distribution from generation and electricity sales.[77]

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[75] UK's Competition Commission, 2001, p. 91.

[76] www.nordpool.com

[77] IEA (2001).

Most market monitoring was at the national level until recently. However, with the increasing share of electricity traded across borders, the market surveillance of Nord Pool has been reinforced. At the end of 2000, Nord Pool decided to strengthen the monitoring of its physical and financial markets by creating an independent dedicated department. Some of the features of market monitoring include:

- An obligation for Nord Pool participants to "disclose market sensitive information".[78] This type of information (for example about incidents related to the power system, maintenance) is provided first to Nord Pool. The rules are in the process of being defined.

- Flagging bilateral-market agreements. This is a proposal by Norway's parliament: all bilateral market trade in standardized financial power contracts within imposed deadlines would have to be notified.

- Nord Pool tries to obtain full "authority to investigate situations to determine whether there has been undue exercise of market power or insider trading".

- Nord Pool is also considering the creation of an ethics council entitled to make statements and recommendations, but not to impose sanctions.

Australia

The restructuring of the electricity market was initiated in 1995 with the adoption of a comprehensive plan to create a competitive National Electricity Market (NEM). This wholesale market includes, as of the Summer of 2001, five Australian States and territories and was launched on December 13, 1998. One of the distinctive features of the Australian model is that the Australian Competition and Consumer Commission (ACCC) is both the national electricity regulator and the competition authority.[79] Furthermore, the ACCC also covers gas, telecommunications and airports. The states and the central Commonwealth government cooperate through the Council of Australian governments. States have a rather wide responsibility in protecting competition and consumers.

The ACCC investigates market arrangements and behavior that may contravene antitrust laws. Tracking misuse of market power is also one of its roles, according to the Trade Practices Act 1974. The Commission is composed of seven members, appointed by the federal government after consultation with the states. Their five-year term is irrevocable and they can be re-appointed. The ACCC is financed through the Treasury's budget, with a small amount coming from authorization fees and fines. The state regulation authorities also monitor market conduct of retailers and distributors.[80]

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[78] www.nordpool.com

[79] www.accc.gov.au

[80] IEA (2001).

One of the characteristics of the Australian market surveillance system is the very short lag (one day) in releasing bid data in the wholesale electricity market. Anyone can consult this information at the following link: http://www.nemweb.com.au:9080/REPORTS/CURRENT/YESTERDAYS_BIDS_REPORTS/[81]

The ACCC cooperates with the National Electricity Code Administrator (NECA) to ensure the "effectiveness, efficiency and equity of the national electricity market".[82] NECA has a market surveillance program through which "variations between forecast spot prices and actual spot prices" are analyzed. According to the National Electricity Code (Clause 3.13.7), the ACCC predetermines the acceptable thresholds for this gap between forecast and reality. NECA "will report incidents where it finds that significant variations are caused by activities that in its opinion are inconsistent with the objectives of the market" and notify the ACCC. NECA also performs routine monitoring of market participants.[83]

NECA is also entitled to establish reporting requirements from the market participants. NECA can thus obtain data on registration, prudence requirements, market operations, rebidding, and settlements. NECA provides, among other publications, annual public market reports.

Germany

Germany was perceived as a success story of electricity restructuring for consumers when its electricity market was liberalized in April 1998 (following the 1997 EU Electricity Market Directive). It ended 100 years of local monopoly supply and combined a negotiated third-party access model with an optional single buyer approach for small municipalities (to preserve cross-subsidization of other public services). Average industry tariffs dropped by 27 % between April 1998 and the end of 1999.[84]

The main reason for this drop in prices was an intense price war from the incumbents. This predatory pricing strategy of matching or undercutting best prices was intended to preserve market shares and prevent new competition. The downward trend in prices created a benign regulatory attitude towards mergers. Also, before January 1999, energy was not

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[81] Note that similar data is available for the English and Wales' market at http://www.esis.co.uk/market/registration.html

[82] From NECA's web site, at www.neca.com.au

[83] A memorandum of understanding between the ACCC and NECA can be found on the NECA web site (http://www.neca.com.au). The guidelines for NECA investigation can be found at http://www.neca.com.au/SubCategory.asp?SubCategoryID=179

[84] Bower et al. (2001).

covered by the German anti-trust law and monopolies were, thus, tolerated.[85]

However, this first competitive environment may be altered in the coming years, as underlined by Bower et al. (2001) in an article in *Electricity Policy*. There has been a large movement of concentration in the German market, starting in September 1999 when VEBA and VIAG, two German conglomerates with electricity subsidiaries, announced their intention to proceed with the largest merger in German history.

The VEBA/VIAG merger and another major merger between RWE and VEW were authorized in early 2000, but the European Commission insisted that this authorization was conditioned on divestment of shares in commonly-owned generators, scrapping of the transmission tariffs between North and South Germany and agreement to sell or auction cross-border transmission capacity where there appeared to be constraints (Bower et al., page 990).

Germany refused to create an Independent System Operator. The regulation of grid access and transmission pricing was negotiated directly by associations in the electricity industry and heavy industry. The first associations' agreement, reached in May 1998, was modified in January 2000, after some problems with high transmission prices and denial of access occurred. There is no dedicated electricity regulatory body and the German Cartel office deals with concentration issues. The EU anti-trust authority also has authority.

There is thus a continuing potential for the exercise of market power in Germany. Although the market has been rather atomistic in the past, it no longer is. The electricity companies were also vertically integrated up to now, but this may change, too. Thus, although Germany may be considered by some as a platform for an EU-wide model, it does not appear to be equipped with sufficient regulatory tools to monitor market power in the future.

[85] This illustrates, more broadly, a higher tolerance for concentration in the German economic environment and regulation. This contrasts with more aggressive anti-trust attitude in Anglo-Saxon countries.

Appendix C
Market Monitoring Indices of California and PJM

For PJM (from the PJM MMU Report to the FERC: *Assessment of Standards, Indices and Criteria*, April 1, 2001).

1. Summary statistics for PJM system by hour/day/week/month/year.
    a. PJM system prices and loads: day ahead and real time markets.
        i. Average PJM load weighted price;
        ii. Maximum PJM load weighted price;
        iii. Average PJM load;
        iv. Maximum PJM load;
        v. Correlations between PJM prices and loads.
    b. PJM congestion.
        i. Maximum hourly congestion costs;
        ii. Total congestion cost;
        iii. Number of active constraints.
    c. PJM volumes.
        i. Total MW bid;
        ii. Total MW self scheduled;
        iii. Total bilateral contract MW;
        iv. Hourly net imports and exports including all components.
2. Day ahead market
    a. Total hourly load
    b. Composition of load
        i. Fixed price bids
        ii. Price sensitive bids
        iii. Decrement bids
    c. Composition of supply offers

i. Generation offers

ii. Increment offers.

3. Aggregate relationships between day ahead and real time markets

   a. Hourly aggregate LMP comparisons

   b. Hourly aggregate load comparisons

   c. Hourly aggregate congestion comparisons

4. Comparative prices and loads for PJM and surrounding power markets:

   a. Forward prices for each system by market term;

   b. Forward price spreads by market term;

   c. Real time prices as available;

   d. Real time price spreads;

   e. Loads for each system as available;

   f. Net imports/exports between PJM and each system.

5. Locational prices and loads.

   a. Bus locational marginal prices (LMPs);

   b. Aggregate LMPs;

   c. Bus LMPs less the PJM average price;

   d. Loads and generation by bus;

   e. The distribution of LMP rankings for each bus by bus price and by bus load/generation;

   f. Daily/weekly/monthly price-load comparisons:

      i. Maximum bus LMP by hour;

      ii. Minimum bus LMP by hour;

      iii. Average load LMP by zone, by aggregate load bus, for PJM;

      iv. Average generation LMP by zone, by aggregate load bus, for PJM;

      v. Load/injections by bus, by zone, by aggregate buses, for PJM.

g. Zonal LMPs

    i. Zonal daily LMP

    ii. Highest bus LMP within zone;

    iii. LMP ranking across zones.

6. Congestion by hour/day/week/month/year by bus/zone/bus aggregates.

    a. Total congestion costs for period;

    b. Peak congestion costs;

    c. Percent of time with congestion;

    d. Frequency of individual constraints;

    e. Frequency of must run price cap implementation;

    f. Frequency of constraints without must run price cap implementation.

7. Transmission congestion and FTR revenue adequacy.

8. Congestion comparisons between day ahead and real time markets

    a. Total congestion costs for period;

    b. Peak congestion costs;

    c. Percent of time with congestion;

    d. Frequency of individual constraints;

    e. Frequency of must run price cap implementation;

    f. Frequency of constraints without must run price cap implementation.

9. Offers and dispatch.

    a. Unit offer/supply curves;

    b. Maximum economic offer;

    c. Minimum economic offer;

    d. Company aggregate offer/supply curves;

    e. Aggregate PJM supply curves;

f. Comparisons of unit offer/supply curves to historical offer curves;

g. Comparisons of company offer/supply curves to historical supply curves;

h. Comparisons of aggregate PJM supply curves to historical supply curves;

i. Deviations from requested dispatch, by unit;

j. Ramp rates by unit, by time period, by company.

k. Comparisons of ramp rates by unit type, by company.

l. Operational constraints on offers: start times; minimum run requirements; minimum down times; maximum starts.

m. Start up costs.

10. Comparisons between day ahead and real time offers

11. Relationship between offers and LMPs

    a. Identification of units which set price;

    b. Identification of fuel type of marginal units;

    c. Frequency of individual units setting price;

    d. Frequency of generation owners setting price.

12. Transmission contracts.

    a. Contract quantities;

    b. Service types;

    c. Contract paths.

13. Energy contracts.

    a. Contract quantities;

    b. Service types;

    c. Contract paths.

14. Regulation

    a. Available regulation

    b. Regulation offers

c. Regulation price

d. Aggregate regulation supply

e. Regulation adequacy

15. Spinning.

a. Condenser bids;

b. Condenser costs;

c. Condenser credits;

d. Total condenser MWs;

e. Total spinning requirements.

16. FTR Auction Market.

a. Total market volume offered and cleared;

b. Total market revenue;

c. Average clearing price;

d. Path specific revenue and volume;

e. Source specific revenue and volume;

f. Sink specific revenue and volume.

17. Available capacity

a. Total capacity resources;

b. Total available capacity;

c. Outage status by unit;

d. Frequency of outages, by type, by unit, by time period;

e. Comparisons of outages across units;

f. Company summary outage frequency;

g. Comparisons of outages across companies;

h. Frequency of unit outages by time period, by demand conditions; by system/bus price.

18. Capacity market
    a. Company supply curves by time period of market;
    b. Company demand curves by time period of market;
    c. Supply/demand balance;
    d. Market prices for each market;
    e. Comparisons of offers to opportunity costs;
    f. Delisting of units by company;
    g. Capacity position by company.
19. Market structure by market
    a. Concentration ratios by hour;
    b. Incremental concentration ratios by hour;
    c. Concentration ratios by transmission defined markets within PJM;
    d. Concentration ratios by zone;
    e. Concentration ratios by interface.
20. Price-cost margins
    a. Unit specific price-cost margins;
        i. Compare unit offers to unit costs
    b. Company price-cost margins;
        i. Compare unit price-cost margins by company.
    c. Price-cost margins for marginal units
    d. Aggregate price-cost margins

For comparison, from the California ISO web site (*ISO Market Monitoring and Information Protocol*, Appendix 2)

Data derived from sources partly or wholly external to the markets administered by the ISO and PX

A. Market Clearing Price Indices

1. The percentage of Settlement Periods in which a Market Participant has set, or has submitted bids close to, the Market Clearing Price in the Energy and Ancillary Service markets overall, and in relation to the following time periods or market conditions:

   a. when such Market Participant is:

      i. a net buyer of Energy and Ancillary Services,

      ii. a net seller of Energy and Ancillary Services;

   b. during on-peak hours and off-peak hours;

   c. in different time periods otherwise of relevance to the state of the markets;

   For each of these situations, bids submitted when Congestion is present and those when there is no Congestion will be compared. These indices will also be examined in relationship to other "vulnerable periods" and bidding strategies;

2. the relationships between the Market Clearing Prices in the various markets administered by the ISO and PX, e.g., between the Imbalance Energy market and the Energy and Ancillary Services markets;

3. the record of Market Participants setting Market Clearing Prices in the context of the inter-market relationships as described in (2);

4. The percentage of Settlement Periods in which a Market Participant has set, or has submitted bids close to, the Market Clearing Price when such price falls into a particular segments of the market price curve, e.g., $20-30/MWh, and $30/MWh and above;

5. A "price mark-up" check that measures the differences in Market Clearing Prices between unconstrained periods and constrained periods.

B. Comparison and Evaluation of Specific Bidding Strategies of Market Participants

1. Correlation between bidding behavior of Market Participants and

their establishing the Market Clearing Price at times when they are:

i. net buyers of Energy and Ancillary Services,

ii. net sellers of Energy and Ancillary Services;

2. bidding and rebidding strategies of Market Participants, especially those that frequently set Market Clearing Prices during iterations in the bidding cycles of each market, both within and between the markets administered by the ISO and PX;

3. comparison of bidding strategies for the same Generation Unit into Day-Ahead Market, Hour-Ahead Market and Imbalance Energy markets;

4. comparison of bidding strategies for the same Generation unit into the Energy, Ancillary Service and Imbalance Energy markets;

5. comparison of Supply Bids of Generation units with similar technology/age characteristics;

6. Supply Bid and Generation Unit withdrawals and redeclarations during bidding cycles;

7. correlation of changes to initial Supply Bids with Market Clearing Prices, e.g., to ascertain if redeclarations cause or lead to increases in such prices;

8. comparison of bidding strategies for the same Generation Unit in relation to the following time periods or market conditions:

. when the Market Participant that owns the unit is a net seller or a net buyer of Energy or Ancillary Services;

a. when congestion is or is not present;

b. when a Reliability Must-Run Unit is called or not called;

c. when "near Congestion" occurs. "Near Congestion" means the final scheduled power flow over an Inter-Zonal Interface is within a few percentage points of the Available Transmission Capacity, or when congestion would occur with the initial Preferred Schedules but is alleviated after rebidding;

9. comparison of bidding strategies of Market Participants in relation to their market share;

10. relationships or correlations between the ability of Market Participants to set Market Clearing Prices or certain type of bidding behavior and periods or circumstances in which such Market Participants may have exclusive or restrictive access to data, e.g., as to costs or availability of Reliability Must-Run Units, or as to expected or actual outages of Generation Units or transmission

facilities;

C. Indices of Market Concentration

The ISO Department of Market Analysis will use dynamic, geographic and product market specific indices based on actual market operation data as indicators of the competitive condition of the ISO and PX markets. The planned indicators are:

1. Market share for the largest supplier.

2. Measure of supply responsiveness. This is a measure of how much additional power would be supplied for a given increase in price.

3. Traditional measures of concentration which might include conventional HHI (Herfindahl-Hirschman Index) analysis.

Indices will be developed for:

4. each of the geographic markets or zones;

5. each of the PX and ISO product markets including Energy, Ancillary Services and Imbalance Energy markets;

6. each of the Day-Ahead, Hour-Ahead and Real Time Markets;

7. each of the market conditions such as on-peak and off-peak periods, periods with Congestion and without Congestion, and periods with and without other constraints;

D. Outages and Other Indices

1. Generation Unit and transmission facility Outage indices in comparison with historical averages, with other similar units or facilities, and with other relevant standards;

2. New or unexpected occurrences of Congestion; and

3. Trend comparisons of Market Clearing Prices with fuel prices and other input prices.

Appendix D: Acronyms and Technical Terms

ADR: Alternative dispute resolution; an option contained in market mitigation procedures that usually allows either party to seek an independent, neutral determination of a disagreement.

Ancillary Services Markets: Markets for services necessary to support the transmission of energy from generators to loads, while maintaining reliable operation of the regional bulk power system; includes reserves, automatic generation service, black-start capability, and installed capacity requirements.

Bid mitigation: Ability of the market monitor to modify the bids entered by the market participants. Bid mitigation is different from price caps: with bid mitigation, only bids are modified, and the price is then set according to the market. With price mitigation, the final price itself is modified.

Bid-stack: The tabulation in ascending order of all the bids submitted; this constitutes the aggregate supply within the market.

Bulk power system: The regional electric supply system administered by an ISO or RTO.

CDR: Capacity Deficiency Rate.

Capacity Market: Generation resources that qualify for installed capacity credit.

De-listing of capacity resources: Removal of capacity and energy from the market.

Day-ahead Market: Part of a multi-settlement market system that provides financial certainty for supply offers and demand bids for energy, at a minimum, and often ancillary services.

ECP: Energy Clearing Price.

FERC: Federal Energy Regulatory Commission, responsible pursuant to the Federal Power Act for ensuring that wholesale electricity tariffs are “just and reasonable.”

FTR (FCR): Fixed-Transmission Right (Firm Congestion Right); a financial contract that entitles the holder to a stream of revenues (or charges) based on the reservation level and hourly energy price differences across a specific transmission path

HHI: Herfindahl-Hirschman Index; used to evaluate the level of resource ownership concentration of an industry or sector.

ICAP: Installed Capacity.

IIA: Interim ISO Agreement; the "contract" between NEPOOL and ISO-NE, approved by FERC, that specifies the ISO's duties and responsibilities.

IMM: Independent Market Monitor

ISO: Independent System Operator

LBMP or LMP: Location-Based Marginal Pricing or Locational Marginal Price.

Load Pocket: An area served by out-of-merit local generators when the existing transmission system cannot import sufficient power to meet local demand.

Load Response Program: Program structured to increase the responsiveness of demand to conditions in supply (especially decreasing demand during peak times when supply may fall short of demand).

Loss of load: Other term for rolling blackout or rotating feeders.

MAAC: Mid-Atlantic Area Council; establishes rules and reliability guidelines for the PJM bulk power system.

MAR: MMU Activities Report

MMIP: Market Monitoring Implementation Plan

MMP: Market Monitoring Program:

MMU: Market Monitoring Unit

MPC: Market Performance Committee.

MSC: Market Surveillance Committee.

MST: Market Services Tariff.

MSU: Market Surveillance Unit.

NE: New England.

NEPOOL: New England Power Pool.

NERTO: Northeast RTO.

NCPC: Net Commitment Period Cost; used to determine a value for compensation for out-of-merit generation pursuant to Market Rule 17 (ISO-NE).

NPCC: Northeast Power Coordinating Council; establishes rules and reliability guidelines for the bulk power systems in NY, NE, Ontario, Quebec, and the Maritimes.

OA: Operating Agreement

OATT: Open-Access Transmission Tariff

Out-of-Merit Generation: Generation that is dispatched for system reliability reasons that would not otherwise be dispatched economically.

PJM: Pennsylvania, New Jersey, Delaware, Maryland and District of Columbia bulk power system.

PX: Power Exchange (California)

RAA: PJM Reliability Assurance Agreement

Real-Time Market: An electricity market recognizing actual generation dispatch (e.g., as opposed to the day-ahead market).

RTO: Regional Transmission Organization

Soft Cap: A cap on an energy supply bid which can be exceeded with appropriate cost justification. Bids exceeding the soft cap do not set the market clearing price, however bidders will be paid the bid amount.

WSCC: Western Systems Coordinating Council; establishes rules and reliability guidelines for the entire bulk power system west of the Rocky Mountains, including portions of Canada and Mexico.