THE REGIONAL TRANSMISSION ORGANIZATION REPORT CARD: WHOLESALE ELECTRICITY MARKETS AND RTO PERFORMANCE EVALUATION

Prepared for

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FOREWORD

Many members of the National Rural Electric Cooperative Association (NRECA), as well as other market participants and state regulators, have expressed concerns that no single document is available to serve as a reference for Regional Transmission Organization (RTO) statistics and to objectively analyze RTO and RTO market performance. Furthermore, growing apprehension among market participants over the total costs of RTO creation and operation has led to the concern that RTO-related costs may exceed the associated benefits.

This study was initiated with the objective of ultimately shedding some light on the questions of how well certain important functions or elements of RTOs are working, and comparing results of various RTO approaches. To do so, the study examines various elements of market performance and market efficiency from a theoretical economic perspective and according to the outcomes produced.

Because of limitations on the data that are publicly available, this report cannot fully answer the question of whether retail consumers are realizing net benefits from the operation of RTOs and their markets. Furthermore, the RTOs' independent market monitors have each chosen different (though partly overlapping) sets of metrics for measuring market performance and market efficiency. These differences are generally reasonable because the RTOs have followed different paths to reach their present market configurations and, although these configurations are similar in many respects, they differ in important design features. Consequently, the Report Card cannot at this time produce an evaluation of each RTO that is based on a uniform set of metrics. However, we expect that over time the metrics used by the various RTOs to gauge markets and RTO performance (including operational and administrative functions and planning processes) will move toward a common set of metrics that will facilitate independent analysis and comparisons over time and across markets.[1]

In the mean time, the RTO Report Card project is intended to fill this informational and evaluative gap by placing the analysis of RTOs and RTO markets on as comparable an analytical footing as possible. This will allow evaluations of each RTO's relative performance and of each RTO's performance over time.

The RTO Report Card project aims to assist the broader universe of market participants and policy makers, as well as NRECA and its members, in understanding the RTOs' performance. It particularly aims to shed light on the structural and design problems that transcend RTO boundaries and thus may signal fundamental design or operational problems requiring attention. The hope is that, by "backing away from the trees," the RTO Report Card will enable a "look at the forest" and therefore provide a stronger foundation for the improvements in market design and for policy guidance for government policymakers and decisionmakers throughout the industry.

[1] The Federal Energy Regulatory Commission (FERC) has amended the Uniform System of Accounts (US of A) to accommodate the unique attributes of RTOs. However, it has not mandated that the RTOs present performance statistics on a standardized basis. Thus, while the US of A is expected to facilitate comparison of the revenues and costs of the various RTOs, comparison of the performance of the RTOs will continue to be problematic.

The RTO Report Card differs from typical RTO annual state of the market reports in several respects. First, it is not authored by RTOs or their market monitors, but rather by an independent consulting firm (Christensen Associates Energy Consulting LLC) that has no vested interest in outcomes in the various RTO markets. The principal interest of the consultant is objective reporting of the facts and objective analysis of the RTOs and their markets using sound economic principles and examination of the available quantitative evidence. Second, the initial edition of the RTO Report Card contains summaries and analyses of two RTOs, but will be expanded in future editions to include the other RTOs. In this first report, the discussion of PJM tends to be longer than that of the Midwest ISO because the greater maturity of PJM's market has allowed a greater accumulation of information, data, and independent analyses. Third, the Report draws from as wide a set of sources as possible in an attempt to provide the reader with an objective picture of the RTOs' markets and to enable comparisons to be made across RTOs and over time.

Again, the RTO Report Card does not address directly the costs and benefits to ultimate consumers of RTOs and restructured wholesale markets, and no report purporting to have done so has been found to provide definitive answers to that fundamental policy question. To do this would require analysis of how generation investment, transmission investment, wholesale power prices, and regulated retail rates would have evolved had there been no restructuring of the wholesale power market in the regions now covered by RTOs. At a minimum, such analysis would involve gaining access to proprietary data that only the RTOs possess.

The RTO Report Card is expected to be issued annually, tracking the historical data and noting trends and major changes in RTO market designs and structures. No other single document exists or is anticipated to exist that would provide such a comprehensive coverage of RTOs.

EXECUTIVE SUMMARY

The National Rural Electric Cooperative Association (NRECA) commissioned Christensen Associates Energy Consulting, LLC (CA Energy Consulting) to objectively examine the performance of Regional Transmission Organizations (RTOs) and the markets they administer. This report is the first of a series of "RTO Report Cards" that will track the performance of major functional elements of selected RTOs over time. This initial Report Card focuses on the performance of the PJM Interconnection LLC (PJM) RTO and the Midwest Independent Transmission System Operator (Midwest ISO).

The Report assesses performance of RTOs and their wholesale markets, and only indirectly by implication examines their retail impacts. Consequently, the Report's references to "customers" are generally to *wholesale* customers of RTO services and RTO market participants such as load-serving entities (LSEs), generators, and transmission customers, not to retail end-use customers. Nevertheless, what transpires in the wholesale markets ultimately impacts retail consumers, so any costs or savings produced by the creation of RTOs and their markets will ultimately be borne or enjoyed by retail consumers to some degree.

General Overview

The RTOs are presently striving to find solutions to several basic market organization questions. These include:

- How can generation and transmission investment be encouraged so that reliability is cost-effectively maintained and electricity prices are less volatile in the long-term?
- What processes shall be used to identify and finance needed transmission investments?
- How shall market power be identified and mitigated?

The RTOs have found, at best, only partial solutions to these questions because no fully satisfactory solutions yet exist in practice or even in theory. It is likely that RTOs will continue to experiment with different approaches to answering these questions, so that basic market design rules will be periodically modified. Consequently, market participants will continue to face uncertainty in the rules of the game as well as additional costs in adjusting their own situations to the changes in design and rules. While the adjustments and evolution of the RTOs, their markets, and market rules may result in greater efficiencies, the additional costs incurred must be borne by participants and ultimate consumers.

The apparent problems of insufficient generation and transmission investment can be traced to a great extent to the short-term (a period of one year or less) nature of RTOs' markets. Short-term markets, as they are currently designed and function in the existing RTOs, do not support a long-term (periods longer than one year) generation and transmission investment process that requires a reasonable level of certainty over the many years of those assets' lives. Because investment is central to the vitality of competition, the short-term focus of the RTO markets and the continuing controversies over investment incentives raise concerns about how well the competitive model will work if it is the sole basis for organizing the electric power industry.

Furthermore, relying solely on the market to build transmission fails generally for reasons that have been oft recited in the academic literature and industry press. Because large numbers of market participants benefit from transmission expansion (the result of "externalities" associated with the interconnectedness of the grid), it is difficult for merchant transmission builders to recover costs from beneficiaries or to find individual transmission customers willing to pay a price high enough to recover their investment in a pure market context. In addition, given that generation and transmission can, in many instances, be viewed as reasonable (but not exact) substitutes in the long run, the independence of generation investment from transmission expansion makes transmission investment by merchants a much riskier proposition than it was in the days when vertically integrated utilities would determine what combinations of generation and transmission investments would best serve their customers' loads. Capital costs are likely to be higher for transmission as a result of the ensuing financial uncertainty. A solution short of pure regulated transmission investment will be difficult to find. In any event, an enhanced long-term planning process will have to consider generation and transmission jointly, with the possibility that market-based generation investment may sometimes be pre-empted by regulated transmission investment.

Market Design and Structure

Market design refers to the rules and procedures by which markets are supposed to work. *Market structure* refers to distribution of resources and obligations among market participants, particularly the ownership of productive facilities. Market design and structure provide a basis for predicting the likelihood that markets will operate efficiently. This is important for evaluating the competitiveness of those markets in which it may be difficult to assess directly the conduct of market participants. In addition, understanding market design and structure provides a foundation for assessing whether consumers are likely to receive net benefits from the creation and operation of these markets by RTOs. Quite often there exists a gap between theoretical predictions and what actually takes place within the implementation of a particular design, simply because there are limitations on the efficiency gains that can be achieved in practice.

PJM has existed as a tight power pool for decades, during which time PJM has been responsible for reliable least-cost dispatch of the power system's generation resources. In 1998, when PJM became an independent system operator (ISO), it continued to centrally dispatch resources within its power grid, but it also began operating a spot energy market. Over the ensuing years PJM introduced new markets and products, and as a result, PJM now has day-ahead and real-time energy markets that use bid-based LMP pricing, a regional capacity market, a financial transmission rights market, and markets for regulation and spinning reserves. Market participants actively trade electricity bilaterally through brokers and the Intercontinental Exchange, often using the PJM Western Hub as the pricing point.

In 1998, PJM included most or all of the power systems in Delaware, the District of Columbia, Maryland, New Jersey, and Pennsylvania (the "Mid-Atlantic Region"). In 2002, PJM integrated the service territory and certain assets of Allegheny Power (AP). In 2004, the addition of the Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Light and Power

(DAY) control areas to PJM increased PJM's peak load approximately 70%. In 2005, the Duquesne Light Company (DLCO) and Dominion Virginia Power (DVP) also joined PJM.

PJM's Market Monitoring Unit (MMU) finds that PJM has "serious market structure issues" because too few sellers own substantial shares of supply in many of PJM's local markets. PJM's energy markets are moderately concentrated overall, but highly concentrated for intermediate and peaking units.[2] PJM's capacity markets and ancillary services markets are also highly concentrated. This suggests that PJM will continue to find it necessary to mitigate market power through offer capping and other measures. Interventions to mitigate market power, which do not clearly distinguish whether high prices are caused by market power or by true economic scarcity, make independent generation investment in PJM somewhat less attractive. In addition, the current high levels of generation reserves in PJM, as discussed later in this report, also contribute greatly to the unattractive environment for investment in new generation.

In spite of moderate to high concentration of generation ownership, the PJM MMU finds that market participants behaved competitively in both 2004 and 2005. Direct evidence that would bear on the question of whether market participants behaved competitively—generator bids and marginal operating costs—are unavailable to us for the 2004 – 2005 period. Therefore, we are unable to confirm the conclusions reached by the PJM MMU. However, indirect evidence does give some support to the MMU's conclusion that the RTO had a workably competitive power market during this period. This indirect evidence includes the convergence of day-ahead and real-time prices, and the decrease in price volatility in the presence of surplus capacity. Furthermore, because 2004 and 2005 were years in which capacity was generally abundant relative to load, the opportunities to exercise market power were limited. The main scarcity-related problems occurred in load pockets created by transmission constraints and by unusually high levels of retirements in some locations, which reduced customers' supply options. Additional evidence that generators were behaving competitively can be found in the downward trend in the offer caps imposed by the PJM MMU during the past several years and the relatively lower percentages of hours and MWs offer-capped in 2004 and 2005. A better test of the robustness of competition in the PJM markets may occur in a future year when capacity becomes tighter.

The Midwest ISO began operating in February 2002, and began its Day 2 Market in April 2005. A key feature of the Day 2 Market is its locational marginal price (LMP) for energy, by which the price of energy may be different at each power system location.

The Midwest ISO presently has no organized markets for ancillary services. However, it proposes to create markets for regulating reserves and contingency (spinning) reserves that will be closely coordinated with the energy markets, in a fashion that is similar to what is done in PJM. In theory, the presence of both energy and reserve markets will induce more generators to commit themselves (i.e., start up) than is the case with only energy markets. Reserve markets could thus provide additional market-based incentives for generator commitment, but it may also bring greater opportunities for generators to exercise market power.

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[2] We cannot provide market concentration measures on a sub-regional basis for PJM because the PJM MMU does not report them on that basis, instead reporting market concentration indices by type of unit—baseload, intermediate and peaking.

In large part because of the absence of reserve markets, the Midwest ISO has had to make substantial special Revenue Sufficiency Guarantee (RSG) payments to generators to ensure that their production costs are fully compensated, and therefore ensure that the generators are willing to be committed and dispatched by the RTO. These payments were $600 million in 2005. A significant portion of these payments was made to maintain reliability in load pockets. Because these payments are associated with maintaining reliability of the system, all load-serving entities (LSEs) have been held responsible for a portion of these payments (including virtual transactions) based on deviations from day-ahead schedules; and market participants have had no way to hedge these costs. The Midwest ISO has acknowledged that there are problems with the RSG that need to be fixed, and has begun to make appropriate changes to the design of the energy markets that include the creation of reserve markets and changes to the energy pricing methods.

The Midwest ISO footprint has over 150 distinct owners of generation; but because of transmission constraints, competition is assessed at the subregional level. The Midwest ISO's Central sub-region is moderately concentrated, while the East, West, and Wisconsin-Upper Michigan Systems (WUMS) subregions are highly concentrated.[3] In each of the latter three sub-regions, the top three suppliers control around 75% of supply. In the Central and West subregions, there are single "pivotal" suppliers whose capacity is absolutely essential to meet load obligations in 20% of all hours, while in WUMS, there are single pivotal suppliers in more than 75% of all hours.[4] Consequently, the Midwest ISO finds that "the most significant potential competitive concerns in the Midwest are in the WUMS area."

During 2005, there were active Broad Constrained Area (BCA) constraints with at least one pivotal supplier in two-thirds of the hours; and there were active Narrow Constrained Area (NCA) constraints with a pivotal supplier in almost 30% of the hours.[5] Hence, there are substantial local market power issues associated with both types of constraints. Nonetheless, FERC recently enjoined the Midwest ISO from mitigating market power problems associated with BCA constraints, which means an exercise of market power may go unchecked and wholesale customers and end-use consumers may sometimes pay above-competitive prices for electricity.

[3] The Central sub-region is essentially the Mid-America Interconnected Network (MAIN) region. The East sub-region is essentially the former East Central Area Reliability Coordination Agreement (ECAR) region. The West sub-region is essentially the former Mid-continent Area Power Pool (MAPP) region.

[4] In a given hour, a supplier is considered pivotal if the total supply *of other suppliers* is less than total demand.

[5] A Broad Constrained Area (BCA) is defined as an electrical area in which sufficient competition usually exists even when one or more transmission constraints are binding, but in which a transmission constraint can result in Locational Market Power under certain market or operating conditions. A Narrow Constrained Area (NCA) is defined as an area in which resources capable of relieving a binding constraint are owned or controlled by a limited number of suppliers, defined initially as fewer than three suppliers.

Market Performance

Market performance refers in this Report to the efficiency with which wholesale electricity markets have actually delivered services to consumers. The actual performance of a market can be measured partly by price trends and partly by the relationship between the market-clearing price and marginal cost, as well as by the relationship of day-ahead prices to real-time spot prices. In general, price stability is good, and prices that approximate marginal costs are good. Nonetheless, rising electricity prices may not indicate a performance problem if fuel prices are rising; and recovery of fixed costs requires that prices sometimes exceed marginal costs. For RTOs that operate a day-ahead market and a real-time market, convergence of the prices in these two markets is an indication that market information and operational assumptions for the day-ahead market enable market participants to form reasonably accurate expectations about what the real-time prices will be the next day. Convergence provides indirect evidence that the market is operating efficiently.

For wholesale markets in all regions of the U.S., market-clearing prices of electricity rose in 2005 over 2004. The dramatic rise in fuel prices, especially those of natural gas, has been one of the primary drivers.

In PJM, hourly real-time prices in 2004 generally ranged between $10 and $70 per MWh, while in 2005 they generally ranged between $20 and $110. This rise in market prices primarily reflects increases in fossil fuel (i.e., gas and coal) prices and the impact of the market clearing price mechanism. Nonetheless, the percentage rise in wholesale electricity prices has been less than that of natural gas. At least two factors may be contributing to this. First, the investment boom in more efficient gas-fired generation during the period 1999 to 2002 has led to improvements in average generating fuel efficiencies. Second, natural gas-fired generators make up only a portion of the generation in the region, and such generators are on the margin (i.e., setting the market-clearing price) only a portion of the time (18% of the time in 2000 rising to 26% in 2005).

The separation among PJM's average zonal prices grew from 2004 to 2005. This is due primarily to the fact that demand (large population centers and industrial activity) is higher in the eastern and southern regions and the less expensive generation is located in the western region of PJM. Transmission constraints impede flows from west to east meaning that higher cost generation in the eastern and southern regions must be dispatched to satisfy demand. If there were no transmission constraints, the unconstrained transmission flows would be expected to reduce or eliminate the differences among the zonal prices. However, the separation in zonal prices between the western and eastern region prices suggests that the growing transmission congestion and losses prevent this gap from closing. The total congestion cost in PJM in 2005 was $2.1 billion.

In the Midwest ISO, some evidence suggests the energy market may be operating efficiently. First, there is a general convergence between the Midwest ISO's day-ahead prices and real-time prices. Second, the Day-Ahead Market has been an accurate predictor of real-time conditions: excluding the effects of the Ludington Pumped Storage facility. Day-Ahead scheduled MWs have been within 1% of Real-Time scheduled MWs. The convergence of day-ahead and real-time prices is partly attributable to the active market in day-ahead virtual trades. Indeed, according the Midwest ISO's Independent Market Monitor (IMM), "almost all of the price-sensitivity on the demand side in the Day-Ahead Market is provided by the virtual traders rather than by physical loads." Despite its significant benefits in promoting the efficiency of the Midwest ISO's energy markets, however, virtual trading may have been significantly damaged by FERC's recent decision to require the Midwest ISO to adhere to the language in its Open Access Transmission Tariff (OATT) and impose RSG uplift charges on virtual transactions.

On the other hand, there is other evidence that suggests inefficiencies in the energy market. First, the large level of real-time congestion costs indicates significant day-ahead misforecasts of line limits, external loop flows, and other factors. Second, WUMS and Minnesota seem to have experienced significant amounts of unanticipated day-ahead congestion.

Third, as recognized by the IMM, the Midwest ISO market is biased in a manner that encourages load to under-schedule in the Day-Ahead Market. Market design flaws, such as the lack of formal reserve markets, energy market prices determined independently of reserve prices, and the Midwest ISO's liability for unit commitment costs incurred in the Reliability Assessment Commitment process, have resulted in day-ahead loads that are consistently less than real-time loads. As an example of such a market design flaw, peaking units set energy prices when their bids are accepted in the day-ahead market; but they do not set real-time energy prices if their operational inflexibility makes them unresponsive to small changes in loads. A better market design would have energy prices reflect the incremental costs of such peaking units when they are dispatched above their operating minima.

Fourth, the real-time market's performance has been compromised by generators offering to the market less than half of their apparent operational flexibility. This withholding of flexibility raises the costs of generating electricity, and can also create or exacerbate transmission constraints. This lack of generator flexibility generally depresses real-time prices, but it simultaneously increases RSG uplift costs that cannot be hedged by LSEs. The Midwest ISO recognizes that market rules and procedures may need to be changed to encourage more flexibility from generators.

Although generators in the Midwest ISO *have* market power, several pieces of evidence suggest that their behavior during 2005 was consistent with that obtained in a competitive market. Generator outage rates were consistent with those of previous years. Deratings and outages were about the same under peak load conditions as they were otherwise; and the deratings of the largest suppliers were generally lower than those of other suppliers. Bids that appear excessively high were low in number, *although this may be due to the high "markup thresholds" of 50% and 100% used by the IMM in its identification of excessive bids*. And generators produced for the market all but a couple percent of the power that appeared to be economic in each hour; although, as just mentioned, the lack of generator flexibility could indicate a market power problem.

Generation Investment

The U.S. power industry is still working off the generation surplus that arose from the irrational exuberance for gas-fired generation investments in the late 1990s and early 2000s. As of 2005, all regions except the Midwest had planning reserve margins in excess of their 15% to 18%

targets.[6] Until natural gas prices spiked in 2005, resulting in high electricity prices whenever natural gas-fired units set the market electricity price, wholesale customers generally have benefited from the resulting downward pressure that this surplus exerts on market prices. At the same time, owners of natural gas-fired generation units generally experienced reduced profitability, thereby discouraging new gas-fired generation investment. With high gas prices, existing nuclear and coal-fired generation have generally been in an excellent position to profit substantially from the increase in market-clearing prices, in contrast to the situation that prevailed when gas prices were lower and market prices of electricity were apparently insufficient to induce substantial investment in new merchant coal-fired capacity.

There has thus been a falling trend in merchant generation capacity additions during the past few years which is likely to eventually result in higher market prices to consumers in future periods as the current excess capacity is absorbed into the market. The sharp rise in natural gas prices, the preponderance of gas-fired generation among the investments of the past decade, and the accompanying dearth of new baseload generation, is increasing the relative attractiveness of investments in non-gas technologies as the capacity surplus gets worked off.

The fundamental problem with market-based investments in power generation is the same as the problem with market-based investments in any other capital-intensive industry: imperfect market forecasts combined with long construction periods lead to market instability. When output prices are high, investors tend to over-invest, which can lead to a surplus and a price bust some years hence. When output prices are low, investors tend to under-invest, which can lead to a shortage and price spikes some years hence.

But for power generation, the problem is more challenging than in most other markets because the other markets generally have greater leeway in balancing supply and demand. For example, most capital-intensive industries, like the automobile industry, have the ability to store their products for some period of time. As another example, most capital-intensive industries, like the airline industry, have the ability to freely change the price of their services without running into major political and regulatory problems. Under regulation, the power industry balanced supply and demand by overbuilding generation capacity. The over-building occurred for several reasons: because generation capacity comes in discrete sizes that makes matching capacity to local load imprecise; because capacity was constructed to meet uncertain long-term load growth; and because regulation assigns a very high value to reliability. While overbuilding has been regarded as economically inefficient, the regulatory model did manage to provide reliable service at stable prices based upon cost-of-service. A major challenge that RTOs face is to match that performance standard.

In the current restructured power industry, the problem of balancing supply and demand can theoretically be solved by either unlimited price flexibility, or unlimited outages of those customers who lack contractual rights to sufficient supply at times of shortage, or assured cost recovery for generation investors. Since none of these three options appears to be politically feasible, the industry is heading for a solution that will most likely be some combination of these three options; but it is impossible to predict whether it will find a workable solution before the next crisis occurs.

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[6] The WUMS sub-region of the Midwest ISO is a counter example where capacity shortages are predicted to occur as early as 2008 if no new generation or transmission capacity is built for the sub-region.

In PJM, in part due to the surplus of capacity, market-clearing prices have induced a low level of new generation investment that PJM regards as a serious threat to reliability a few years hence. Additions of new capacity in the past couple of years have been offset to some extent by sizeable amounts of capacity retirements, a trend that is expected to continue into the future. Even though the PJM region as a whole currently has an abundance of generation capacity, it also has localized generation resource adequacy problems that arise primarily from transmission limitations.

PJM believes that the present capacity market design is contributing to the perceived lack of adequate investments in new generation capacity, implying that the capacity market needs reform. PJM's proposed solution, the Reliability Pricing Model approach, is a partial return to centralized planning and regulated generation prices and is therefore a move away from competitive market solutions. The PJM proposal has been very controversial among market participants and is now being litigated before FERC.[7]

In the Midwest ISO, the current resource adequacy requirement basically piggy-backs on the resource adequacy requirements of the states in which loads are located. Load-serving entities (LSEs) must meet these requirements according to the locations of their loads, not their resources. If a state lacks a resource requirement or has an indeterminate resource requirement, the Midwest ISO imposes an annual reserve requirement of 12% of the load located in that state. It does not appear that the Midwest ISO has penalties or other mechanisms by which it ensures compliance with its resource adequacy requirement.

Because of the surplus generation capacity in the Midwest, at the margin, according to the Midwest ISO, "(t)he net revenue (revenues less production costs) produced by the energy markets was well below the levels necessary to invest in new generation." In each of the Midwest ISO's four sub-regions, neither new combustion turbines nor new combined cycle units would have been able to recover their capital costs, indicating that new generation investment in these generation types would not have been immediately profitable. This lack of profitability for new and recent gas-fired investments is a reflection of the current generation surplus throughout the Midwest ISO footprint: prices are properly signaling the fact that new generation is presently unneeded. Nonetheless, the Midwest ISO region witnessed about 2,000 MW of capacity additions in 2004 and about 2,600 MW of additions in 2005.[8] The dark spreads in the Midwest suggest that existing coal-fired plants have been profitable, even though market-clearing prices may not yet be high enough to ensure that new coal-fired investments will be so.

Transmission Investment

At the national level, miles of high-voltage transmission-lines increased by 0.6% in 2004, in contrast to a 2.3% increase in the capacity of the electric generating fleet, while load growth has averaged roughly 2.5% over the past five years.[9] This would suggest that investment in

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[7] A consultant for the Pennsylvania Office of Consumer Advocate has forecast that consumers would be paying between $3 and $4 billion per year more for generation capacity under the PJM proposal. See http://www.pennfuture.org/media_e3_detail.aspx?MediaID=189&TypeID=3.

[8] Midwest ISO, *2005 State of the Market Report*. We have not determined how much of the capacity additions were by merchant generators.

[9] Information on high-voltage transmission investment for 2005 was not available at the time of this writing.

transmission that is critical in linking generation to loads continues to lag behind generation and load growth. The results of this dearth are evident in the overall increase in congestion costs and the still frequent use of Transmission Loading Relief procedures. While there appears to be a continuation of the low level of high-voltage transmission investment that has persisted since the early 1990s, dollars of investment in overall transmission plant have increased at a rapid 13.1% compound annual rate between 2000 and 2004, although the base to which this growth rate has been applied was low as a result of a lack of transmission investment during the preceding decade. According to the *EEI Survey of Transmission Investment*, total gross transmission investment by integrated utilities and stand alone transmission companies was projected to be $5.7 billion in 2005 and reach $6.1 billion by 2008. According to EEI, gross transmission investment was actually $5.8 billion in 2005.[10] While numbers on gross transmission investment do not reveal whether there has been a reversal of the previous trend for high-voltage transmission, the numbers suggest there may be a resurgence of investment that could contribute to closing the apparent gap.

Thus far, PJM and the Midwest ISO's transmission planning processes lack teeth, as the RTOs seem to have no authority to mandate the building of economic upgrades, which are defined as additions needed to reduce congestion costs, or even to determine that the most cost-effective regional upgrades ought to be built first. Prioritization of transmission upgrades is essential to RTOs' successful implementation of transmission planning processes; and yet, at the present time, such prioritization is merely an idea for discussion in some RTOs.

One of the impediments to transmission investment is the arbitrary distinction made in some RTOs between "reliability upgrades" and "economic upgrades." Reliability-based investments always allow reductions in generation redispatch costs that also would be expected to reduce market-clearing prices; and economic-based investments always provide reliability benefits. The distinction is made in the continuing hope that the market will build economic upgrades, but experience throughout the world indicates that this is more a hope than a reality. The unfortunate result of trying to distinguish between "reliability upgrades" and "economic upgrades" is that the distinction has permitted continued under-building of transmission facilities that planning processes clearly indicate would provide net benefits to wholesale customers and retail consumers.

In PJM, transmission planning has not met the goals of PJM and many LSEs. Of the $2 billion of transmission upgrades that PJM has authorized since 2000, most have been short-term "reliability" upgrades, with most of the remaining upgrades used to interconnect new generation. By contrast, "economic" upgrades, which reduce transmission congestion costs and improve market access, have not happened in significant amounts, despite the fact that congestion costs have been increasing on an absolute (i.e., total cost) and a per-MWh of delivered energy basis over the past several years. Of the eleven "economic" transmission projects listed in the PJM 2005 Regional Transmission Expansion Plan (RTEP), only one was placed in service in 2005, one was under construction with projected in-service date of early 2007, and the remaining nine projects were in some stage of the study process.

On the other hand, two major high-voltage transmission projects have recently been proposed by American Electric Power (AEP) and Allegheny Energy (Allegheny). If they are approved and

[10] Source: *Electric Utility Week*, 6/26/06, p. 1.

built, these projects will improve west-east flows through PJM and have substantial potential economic benefits. However, these two proposals appear to have occurred more in response to the economic incentives embedded in the Energy Policy Act of 2005 than to the RTO's transmission planning process, as they have been proposed outside of that planning process.

PJM is considering extending the duration of its planning horizon from the current 5 years to up to 15 years, incorporating a new "economic efficiency" component into the RTEP process, and providing a direct link between the transmission planning process and the creation and maintenance of long-term Financial Transmission Rights (FTRs). These changes are partly motivated by a desire to induce investment in "economic" upgrades and to provide a link between long-term transmission rights and new generation investments.

In the Midwest ISO, the transmission planning process is in a developmental stage. The process currently looks about five years into the future and creates the Midwest Transmission Expansion Plan (MTEP), which identifies "Planned" and "Proposed" transmission projects. The Midwest ISO does not independently evaluate whether these projects are the most efficient solutions to identified reliability issues. Furthermore, these projects apparently include only those that are needed for reliability purposes, not those that allow substantial reductions in congestion and generation costs. The Midwest ISO intends to recommend congestion-reducing transmission plans when a collaborative stakeholder process determines how to identify such economic projects and how to determine cost responsibility. In summary, the Midwest ISO's transmission planning process assures short-term reliability, but does not necessarily provide least-cost transmission plans either for reliability in isolation or for reliability and economics together. And while the Midwest ISO does not yet have in place mechanisms that satisfy the requirements of the Energy Policy Act of 2005 for long-term financial transmission rights, this is one area that will be receiving attention from the RTO and its market participants.

Agreement has not yet been reached on the assignment of cost responsibility for transmission expansion, even for reliability upgrades. The costs of load-growth driven upgrades seem to be allocated to the local Transmission Owner constructing the upgrade. The Midwest ISO has proposed that the costs of other projects needed to maintain system reliability be allocated according to Line Outage Distribution Factors, except that 20% of the costs of projects rated 345 kV and higher be allocated regionally through a system-wide rate. A decision on the Midwest ISO's proposal is pending at FERC. For economic upgrades, the Midwest ISO is planning on submitting a proposal for cost allocation to FERC in late 2006.

The most recent MTEP shows sharp upward trends in planned, proposed, and total transmission investments through 2008. After 2008, plans apparently become more uncertain, as most investments are merely proposed rather than planned, and the total volume of investments falls.

Transmission Congestion

Transmission congestion limits the ability of low-cost generation to reach loads. By limiting the geographic scope of markets, it can also create or exacerbate local market power problems in energy and reserve markets. In addition, congestion on transmission lines linking adjacent RTOs requires reciprocal agreements on how to manage such congestion, which in turn, creates issues of how to allocate the costs of inter-RTO congestion management efforts.

In PJM, the overall trend in total congestion costs has been upward since the inception of the LMP-based energy market in 1999, reaching $2.1 billion in 2005. In recent years, the major increases in congestion have been largely due to PJM's expansion, because congestion that was formerly located *outside* of PJM is now instead located *inside* of PJM. Congestion costs have also been increasing on a per-MWh basis, though not as a percentage of total PJM billings. Statistics on the numbers of constrained hours, constrained facilities, and congestion-event hours present a mixed picture: although the frequency of congestion events within PJM has increased over time, there were overall decreases in congested hours experienced on most interfaces, transformers, and lines during 2004 as compared to 2003, but generally increases in congested hours for 2005 compared to 2004. Consequently, it is not clear whether the integration has resulted in any significant change in congestion for the region that PJM now encompasses.

In the Midwest ISO, prior to the April 2005 introduction of LMP and the Day 2 Market, there were significant problems with Transmission Loading Relief (TLR) calls (i.e., transmission service curtailments) and rejections of short-term reservation requests. In fact, during the years 2002 through 2004, most requests were refused. The problems with TLRs were so bad that, in 2004, Midwest ISO flowgates accounted for most of the TLR calls in the Eastern Interconnection, with the WUMS region experiencing more TLRs than any other Midwest ISO sub-region.

The Day 2 Market has had little effect on the *number* of TLR calls, but seems to have had a substantial effect on the gigawatt-hour (GWh) *volume* of TLR calls. The number of calls was down only slightly in 2005 relative to 2004; but the GWh volume of TLR calls declined by 76% from 2004 to 2005. Because the cost of TLR calls is related to the GWh volumes, the Day 2 Market may have improved the efficiency of congestion management, although at this point it is difficult to quantify.

Nonetheless, the Midwest ISO still has to contend with some serious congestion issues, some of which may be resolved with experience and with improvements in market design. These issues include the following:

- In 2005, an astonishing 25% of the Day 2 Market's congestion was "unmanageable," meaning that the ISO was unable to keep transmission flows within the bounds of transmission constraints on a 5-minute basis. The IMM says that this problem arises from generators' unwillingness to offer the redispatch capability that they have, and from a Midwest ISO modeling rule that limits Midwest ISO's ability to redispatch certain generators, even when those generators are willing to help manage transmission constraints. The IMM has proposed remedies for these problems.
- When constraints are unmanageable, LMPs are mathematically undefinable. Under such circumstances, the Midwest ISO produces LMPs by resorting to an artificial pricing rule that under-prices congestion, which sends an inefficient price signal to transmission customers. The IMM has proposed a remedy that is expected to improve the pricing (i.e., make it more efficient) but will not fully solve the pricing problem.
- Congestion costs in the real-time market were almost a third of the total congestion costs. This large level of real-time congestion costs indicates significant day-ahead misforecasts of line limits, external loop flows, and other factors.

Transmission Rights

In PJM over the past several years, market participants have generally received about three-fifths of the transmission rights that they request, and those rights have generally been worth about 95% of their nominal values. The net result is that just over half of transmission congestion is hedged, while the unhedged remainder imposes risks that are ultimately borne by customers, especially those in load pockets (e.g., customers in the Delmarva region of PJM).

PJM has not yet developed a market for long-term transmission rights. Rights are presently available for no more than one year into the future, with essentially automatic annual renewal of those rights based upon historic usage. Recently, however, some load-serving entities have had their allocations reduced by as much as 50%, which suggests that there has been an erosion of the concept of automatic rights because of the limits of the simultaneous transfer capability of the grid. Participant working groups are currently discussing proposals that would establish and allocate a portion of FTRs for up to a ten-year period. FERC Order No. 681, which addresses this issue, gives new impetus to these proposals by requiring the RTOs to develop and administer long-term FTRs.

PJM has recently had stable or falling prices for FTRs of up to one year's duration, a development that, if it continues, could reduce risk in the short-term FTR auction market.

In the Midwest ISO, FTRs were fully funded in 2005: the rights were worth 100% of their nominal values. However, increasing loop flows between PJM and TVA created a funding shortfall for the last three months of 2005. If this problem were to continue over the long term, it potentially could undermine the values of the Midwest ISO's FTRs. Therefore, PJM, the Midwest ISO, and TVA are attempting to resolve the underlying seams problems.

In the Midwest ISO's monthly FTR auctions, the average FTR auction prices generally under estimated the actual value of congestion in the day-ahead market in most months of 2005. The underestimation was greater in the western markets (WUMS and Minnesota) than in the eastern markets (Michigan and IMO) due to the fact that the former market regions experienced significant amounts of unanticipated day-ahead congestion.

Demand Response

Although markets function most effectively when there is a demand-side response to market conditions, few customers receive information or signals on current market conditions—except during extraordinary broadcast appeals for conservation during emergencies—and so most demand is not responsive to current market conditions.

In PJM, there are about 10,000 MWs of responsive load, which constitute about 6% of PJM's total generating capacity. Of this responsive load, PJM itself is directly responsible for 55%, 36% is exposed to wholesale prices, and 9% is enrolled in independent demand-side response programs.

The Midwest ISO has recently reactivated the Demand Response Task Force to address demand response issues. This comes partly in reaction to the Midwest ISO's curtailment requests made during the hot summer of 2006.

RTO Operational Performance

Two control performance metrics, Control Performance Standards 1 and 2 (CPS1 and CPS2), measure how well control area operators balance the supply and demand for power. In particular, these two metrics look at power system frequency (which should be 60 Hz at all times), in the case of CPS1, and Area Control Error (ACE), in the case of CPS2.

PJM believes that it is managing power imbalances well, but that it has experienced some growing pains in connection with its expansion. The evidence indicates, however, that PJM's control performance has declined over time as it has expanded, as both CPS1 and CPS2 have been on decidedly downward trends from 2001 through 2005, although it is difficult to determine whether this is an indication of systemic problems or merely a reflection of the growing pains that PJM has experienced over the past couple of years. Nonetheless, with rare exceptions in the fall of 2004, PJM has complied with CPS1 and CPS2 targets.

No information regarding these measures of operational performance for the Midwest ISO was available at the time of this writing.

RTO Administrative Costs

Over the years 1999 to 2006, PJM's administrative costs generally have been increasing in absolute terms, and experienced a significant jump in 2002 and a slight jump in 2005. However, these costs have displayed a general downward trend since 2002 on a per-unit basis, rising from $0.20 per MWh in 1999 to a peak of $0.80 in 2002 before declining to $0.40 per MWh in 2005 and an estimated $0.35 in 2006. This per-MWh decline suggests that PJM has begun to experience some economies of scale and scope through growth in transactional volumes and through its recent expansion and integration of additional utilities in 2004 and 2005.

The Midwest ISO has accumulated $166 million in Deferred Regulatory Assets, which are past losses that Midwest ISO intends to recover at some future date. While the excess of expenses over revenue was $51 million in 2004, it was only $10 million in 2005. Furthermore, operating costs for 2006 are expected to be about $150 million, $10 million less than initially budgeted.

THE REGIONAL TRANSMISSION ORGANIZATION REPORT CARD: WHOLESALE ELECTRICITY MARKETS AND RTO PERFORMANCE EVALUATION

Christensen Associates Energy Consulting, LLC (CA Energy Consulting) has been commissioned by the National Rural Electric Cooperative Association (NRECA) to conduct research that measures as objectively as possible the performance of the various Regional Transmission Organizations (RTOs) and their markets. This research is motivated by deficiencies in the presently available information on and analyses of the RTOs, and by a rising concern among many market participants, including members of NRECA and the American Public Power Association (APPA), about the total costs of creating and operating RTOs with centrally administered spot energy markets based on locational prices. The concern is that these costs have tended to exceed the associated benefits, and that consumers have seen (or will see) higher electricity prices as a result.[11]

Although there are important similarities among the RTOs' market designs, there is wide variation in the methods that various studies have used to analyze their performance; so it is difficult to assess and compare their performance. Furthermore, there has been little research conducted and no objective standards established upon which to measure certain aspects of performance, such as the effectiveness of RTOs' management of transmission and market administration services. Finally, there is some question about the objectivity of the presently available analyses of RTO performance, particularly when these analyses have been conducted by the RTOs themselves or by their advisors.

The present report is the first of a series of "RTO Report Cards" that will track the performance of various RTOs over time and will aim to cast light on some of the costs and benefits that consumers are deriving from RTOs and their markets. The RTO Report Card project has the following objectives:

1. Develop an objective standardized analysis that can be tracked over time of: a) the various markets that RTOs administer; and b) RTOs' performance in providing services to their transmission owner members and market participants.
2. Develop an empirical foundation for the assessment of public policy initiatives at the Federal Energy Regulatory Commission (FERC) or in Congress.
3. Develop a sound empirical basis for evaluating other studies of the costs and benefits for consumers of RTOs and of centrally administered, regional wholesale power markets.
4. Develop an understanding of how the benefits and costs associated with RTO formation and operation are distributed among the market participants and consumers.

[11] The costs to consumers may also have been increased by market power problems, the public good attributes of the grid that discourage investment, and the separation of grid management and ownership.

This first "Beta Test" version of the RTO Report Card focuses on the performance of the PJM Interconnection LLC (PJM) RTO and the Midwest Independent Transmission System Operator (Midwest ISO), including their energy and related markets. Nonetheless, to give the reader an accurate idea of how the Report Card will look at several RTOs simultaneously, this Beta Test version has placeholders for a third RTO in addition to PJM and Midwest ISO.

Following this introduction, the Report begins, in Section 1 with a discussion of significant recent developments in the RTO markets. Section 2 describes the RTOs' market designs and presents statistics concerning their market structures and performance. Section 3 looks at generation investment and adequacy. Section 4 describes trends in transmission investment and transmission congestion. Section 5 looks at demand response. Section 6 presents information that indicates how well the RTOs are performing their power system control and administrative functions. Section 7 presents statistics on RTOs' uplift charges and administrative costs, and on market participants' costs of being members of RTOs and participating in RTO-run markets. Section 8 discusses net benefits and costs of RTOs to consumers.

There are three appendices. Appendix A presents background material on electric industry restructuring. Appendix B summarizes and critiques several studies of RTO costs and benefits. Appendix C lists references and data sources.

1. OVERVIEW OF SIGNIFICANT DEVELOPMENTS

This section describes important developments in RTOs over the past several years. Section 1.1 discusses developments in the PJM market. Section 1.2 discusses developments in the Midwest ISO RTO markets. Section 1.3 discusses developments in the third RTO's markets.

1.1. PJM

The major recent developments in PJM include: a) the recent expansion of PJM to include six additional utilities' control areas; b) PJM's proposed locational capacity market, called the "PJM Reliability Pricing Model"; c) proposed changes to the Regional Transmission Expansion Planning Process; d) PJM's proposal for a three pivotal supplier test for market power to trigger offer capping in load pockets; and e) administrative scarcity pricing.[12] Each of these is discussed in turn below.

1.1.1. Expansion of the PJM Footprint

PJM has existed as a tight power pool for decades, during which time PJM has been responsible for reliable least-cost dispatch of the power system's generation resources. In 1998, when PJM became an independent system operator (ISO), it continued to centrally dispatch resources within its power grid, but it also began operating a spot energy market. Prior to April 1998, energy prices varied on a zonal basis. Subsequent market milestones included the following events:

[12] A supplier is considered pivotal if total supply in a given hour would be less than total demand without that particular supplier's offer. Thus, a three pivotal supplier test examines instances when the total supply would be less than total demand without the offers from the top three suppliers.

- April 1998: Introduction of a cost-based Real-Time Energy Market with locational marginal pricing (LMP), with energy prices that vary by location based on offers at cost.
- April 1999: Introduction of a market-based Real-Time Energy Market with LMP.
- May 1999: Introduction of monthly Financial Transmission Rights (FTRs), which hedge market participants against differences in LMPs at source and sink locations.
- January 1999: Introduction of the Daily Capacity Market.
- June 2000: Introduction of the Day-Ahead Energy Market.
- June 2000: Introduction of the Regulation Market.
- December 2002: Introduction of the Spinning Reserves Market.
- June 2003: Introduction of Auction Revenue Rights (ARRs).
- June 2003: Introduction of annual FTRs.

As a consequence of this evolution, PJM now has day-ahead and real-time energy markets that use bid-based LMP pricing, a regional capacity market, a financial transmission rights market, and markets for regulation and spinning reserves. Market participants actively trade electricity bilaterally through brokers and the Intercontinental Exchange, often using the PJM Western Hub as the pricing point.

In 1998, PJM included most or all of the power systems in Delaware, the District of Columbia, Maryland, New Jersey, and Pennsylvania (the "Mid-Atlantic Region"). In 2002, PJM integrated the service territory and assets of Allegheny Power (AP). In 2004, the addition of the Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Light and Power (DAY) control areas to PJM increased PJM's peak load approximately 70%. In 2005, the Duquesne Light Company (DLCO) and Dominion Virginia Power (DVP) also joined PJM. Consequently, PJM has divided 2004 and 2005 into five phases that differ according to their geographic scope. The phases are as follows:

Phase	Months	Mid-Atlantic	AP	ComEd	AEP	DAY	DLCO	DVP
1	Jan-Apr 2004	✓	✓					
2	May-Sep 2004	✓	✓	✓				
3	Oct-Dec 2004	✓	✓	✓	✓	✓		
4	Jan-Apr 2005	✓	✓	✓	✓	✓	✓	
5[13]	May-Dec 2005	✓	✓	✓	✓	✓	✓	✓

Thus, PJM now stretches from the Atlantic Coast to the Midwest; and it includes all or part of the high-voltage electric systems of thirteen states and the District of Columbia. PJM includes all or portions of three North American Electric Reliability Council (NERC) regions: the Mid-

[13] As described in Section 3.1.2.2, Phase 5 is divided into Phase 5-a (May-July) and Phase 5-b (August-December) to recognize structural changes in the Regulation Market.

Atlantic Area Council (MAAC), the East Central Area Reliability Coordination Agreement (ECAR), and the former Mid-America Interconnected Network (MAIN).[14]

To address challenges associated with the expansion (as well as other issues), PJM and Midwest ISO initiated a Joint Operating Agreement (JOA) on December 31, 2003. PJM and Midwest ISO formulated the JOA in partial compliance with a FERC directive to design a seamless market between the two RTOs; so this agreement addresses some (but not all) of the seams issues between the two RTOs. For 2004, the JOA sets procedures for the market (PJM) to non-market (Midwest ISO) interface. With Midwest ISO's central dispatch market startup in 2005, the JOA thereafter set procedures for managing congestion through redispatch based on market prices.[15]

1.1.2. PJM's Capacity Market

On August 31, 2005, PJM submitted to FERC a proposal to modify its existing capacity market rules by instituting a four-year forward locational capacity market referred to as the Reliability Pricing Model (RPM).[16] PJM asserts that its current capacity market fails to assure that reliability will be maintained at the lowest reasonable cost, and that reliability may be at risk.[17] Even with the current generation capacity levels generally in excess of market needs, PJM is concerned that generation investment will not be sufficient to maintain reliability in the future, and that some investment has been in the wrong locations. As evidence, PJM cites a decline in new projects entering or remaining in PJM's generation interconnection queues as well as particular resource adequacy concerns in localized areas. PJM generally attributes the decline in generation interconnection queues and locational concerns to low prices produced by PJM's current capacity market structure and a lack of a locational price signal within that structure. The current excess of generation capacity also accounts for the lack of generation investment in the market.

The primary features of the RPM include: 1) moving from an RTO-wide capacity market to one that values capacity resources based on their location; 2) the use of a downward-sloping "demand curve" to administratively set the price of capacity based on the volume of cleared bids in an annual four-year forward capacity auction;[18] 3) a four-year forward looking capacity commitment requirement; 4) a premium for capacity resources that contribute certain operational characteristics; 5) mechanisms that will permit planned generation, planned and existing demand resources, and planned transmission upgrades to compete with existing generation in capacity auctions; 6) explicit market power mitigation rules; and 7) a reliability backstop mechanism by

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[14] MAIN is now defunct.

[15] Seams problems remain despite the JOA. Midwest ISO and PJM are working to resolve those issues, many of which are related to the impacts of power flows associated with the interconnection of ComEd with PJM through the Midwest ISO footprint and the islanding effects on Wisconsin and Michigan of ComEd and AEP's participation in PJM's dispatch.

[16] PJM Interconnection L.L.C., *Reliability Pricing Model Filing*, Docket Nos. ER05-1410-000 and EL05-148-000, August 31, 2005.

[17] *Ibid*., p. 3.

[18] In RPM, the "demand curve" is called the "variable resource requirement" (VRR) curve. This nomenclature recognizes that the curve is not actually a demand curve that would be determined by the price bids of loads or load-serving entities.

which PJM can procure generation capacity resources if the market fails to do so. The RPM will rely on price signals to address reliability objectives, though these price signals will be largely determined by administrative rules.

Some interested parties have supported the proposal as being necessary to: a) stabilize generation revenue streams; b) make up for the "missing money" that generators do not receive because of price caps and bid caps in the energy and ancillary services markets; c) assure adequate investment in generation; d) induce generation investment in the right locations; and e) put generation investment, transmission investment, and demand-side resources on an equal footing in solving transmission congestion problems.[19] Other parties have opposed the proposal because of concerns that: a) RPM will not produce the desired locational investment; b) RPM will cost more than is necessary to secure the desired locational capacity; and c) RPM is not a market-based approach to solving the reliability and deliverability problems that PJM is experiencing, but is instead an administrative, command-and-control type of mechanism.[20] Several parties indicate that the RPM is a sign that more transmission needs to be built to solve deliverability problems between capacity-rich and capacity-poor areas of the PJM footprint.[21]

In April 2006, FERC issued an order finding that as a "result of a combination of factors, PJM's existing capacity construct is unjust and unreasonable as a long-term capacity solution," but the Commission "cannot at this time find that the RPM proposal as filed … is the just and reasonable replacement for the current capacity construct because certain elements of the proposal need further development and elaboration."[22] FERC further found that:

- locational capacity markets are just and reasonable;
- long-term forward procurement requirements are an appropriate replacement for the current method of allowing daily and monthly procurement of capacity, the length of the forward commitment is yet to be determined;
- the "capacity construct must permit generation, demand response and transmission a reasonable opportunity to compete in solving reliability concerns." PJM must continue to

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[19] For example, the comments of Public Service Electric and Gas (PSEG) indicate general agreement with PJM's characterization of the problems with resource adequacy that require a solution such as RPM: "the PSEG Companies also have faced one of the main generation adequacy problems currently confronting PJM, namely the inability of generating companies to receive sufficient revenues to fund the continued operation of older generating units which, although less efficient than their more modern counterparts, are nonetheless critically needed for reliability purposes." Motion to Intervene and Comments of the PSEG Companies, Docket Nos. ER05-1410-000 and EL05-148-000, p. 3.

[20] For example, AMP-Ohio states "PJM's RPM proposal is unfaithful to the MCP (Market Clearing Price) approach currently used in its energy market. The PJM energy market clears prices based strictly on the offers from generators to the market. RPM would administratively and artificially set a price based on the amount of reserves in the region…" See *Protest and Request for Rejection, or, In the Alternative, for Suspension and Hearing on Behalf of American Municipal Power-Ohio, Inc. and Easton Utilities,* Docket No. ER-05-1410 and Docket No. EL05-148, October 19, 2005, p. 24.

[21] For example, see the *Comments of the New Jersey Board of Public Utilities,* and *Industrial Customers Motion to Intervene and Protest of PJM's Reliability Pricing Model*, Docket No. ER-05-1410 and Docket No. EL05-148, October 19, 2005.

[22] Federal Energy Regulatory Commission, *Initial Order on Reliability Pricing Model*, Docket Nos. EL05-148-000 and ER04-1410-000, at p. 6 ("April 20 Order").

work on revising its Regional Transmission Expansion Plan so that it is coordinated with the capacity market;

- it is appropriate to allow states and utilities to determine whether capacity requirements are satisfied through a forward capacity auction approach such as the RPM or satisfied by requiring each LSE "for meeting its locational reliability targets for the procurement period determined"
- the integration of revenues derived from the energy market to determine the slope of the Variable Resource Requirement curve is a "reasonable method of ensuring that changes in energy markets will be reflected in the capacity market" prices.[23]

FERC ordered that the proposal be considered further through a paper hearing and that PJM and stakeholders attempt to reach agreement through a negotiated settlement.

Section 4.2.3 presents additional information about the design of the RPM.

1.1.3. PJM's Regional Transmission Expansion Planning Process

The rules and procedures for the Regional Transmission Expansion Planning (RTEP) process are set forth in Schedule 6 of the PJM Operating Agreement. In accordance with those rules, PJM annually prepares a plan for the enhancement and expansion of transmission facilities to meet demands for firm transmission service and to support competition in the PJM region. The current PJM planning process tests for reliability criteria violations in each of the succeeding five years, but also assesses potential violations beyond that period, up to ten years out. PJM is presently in the process of adopting a 15-year planning horizon. In developing the RTEP, PJM annually tests the adequacy of the transmission system to deliver energy and capacity resources to loads in all areas of the PJM region. The adopted RTEP plan is supposed to include transmission upgrades needed to resolve reliability criteria violations identified in the planning horizon. The plan, with the identified upgrades, establishes the baseline reliable system used in system impact studies for proposed generation or merchant transmission interconnections.

When FERC granted PJM full RTO status at the end of 2002, it directed PJM to revise its regional transmission expansion planning protocol (RTEPP) to "more fully explain... how PJM's planning process will identify expansions that are needed to support competition" and to "provide authority for PJM to require upgrades both to ensure system reliability and to support competition."[24] The FERC approved implementing changes to the PJM Tariff and to its Operating Agreement, expanding PJM's regional transmission planning protocol to include economic planning.

Nonetheless, the RTEP's recognition of the need for "economic" upgrades did not succeed in producing any significant investments in such upgrades. Consequently, FERC ordered PJM to make further changes to its RTEP. Thus, in 2004, FERC approved changes to the RTEP process that allow PJM, in certain narrowly defined circumstances, to order transmission upgrades

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[23] *Ibid.*

[24] Federal Energy Regulatory Commission, *Order Granting PJM RTO Status, Granting in Part and Denying in Part Requests for Rehearing, Accepting and Directing Compliance Filing, and Denying Motion for Stay*, Docket Nos. RT01-2-001 and RT01-2-002, 101 FERC ¶ 61,345, December 20, 2002, p. 20, p. 8.

needed to enhance competition, in addition to those needed to resolve reliability criteria violations. Under these recently implemented rules, PJM relies on its ongoing assessments of transmission congestion to identify transmission upgrades needed to address congestion that is deemed to be “unhedgeable.” Rather than immediately ordering such upgrades, however, the economic planning process incorporates a “market window,” which is a period of time during which market participants can volunteer to finance the transmission upgrades that resolve congestion, in exchange for which such participants receive FTRs commensurate with the transfer capability created by their upgrades. Only if market forces do not resolve such congestion within the window will PJM order construction of transmission upgrades, in which case the cost of the upgrades is recovered through rolled-in pricing.

Until recently, PJM believed that the five-year horizon in the RTEP process was sufficient to identify baseline transmission requirements related to load growth. It has become apparent, however, that at least some potential transmission additions that go beyond simply maintaining minimum reliability requirements are too extensive to be built within the current five-year RTEP horizon. Furthermore, the number of generation projects pending in the interconnection process generally has been lower than it was when the RTEP was first established. Recent experience with generation retirements has increased uncertainty for planners concerning the optimum future system configuration. Furthermore, the PJM Board of Managers (PJM Board) has acknowledged that many market participants were correct in saying that it is not clear that the recently implemented economic planning rules “are achieving the desired outcome of ensuring adequate transmission investment to support robust competitive markets.”[25] Accordingly, in late 2005, PJM’s RTEP process was amended to use a 15-year planning horizon rather than the shorter 5-year horizon employed since the inception of the RTEP process in 2000.[26]

1.1.4. PJM’s Three Pivotal Supplier Test for Mitigating Market Power

Ever since PJM began operating as a FERC-approved ISO, there has been concern about the exercise of market power, especially in load pockets. The two mechanisms that have been relied upon by PJM to combat market power have been the use of a $1,000 per MWh price cap in the energy market and offer caps on energy offers when transmission constraints occur.

PJM has recently instituted a somewhat controversial “three pivotal supplier” test to determine hourly whether suppliers should be subject to offer capping with respect to a particular transmission constraint. A settlement agreement has been reached that permits PJM to apply this test provided that the caps are imposed only on generation suppliers that fail the test, not on all generation within an import-constrained load pocket.[27]

[25] *Ibid*.

[26] PJM News Release, “PJM Approves $464 Million In Transmission System Improvements, Bringing Total Approved Upgrades To Nearly $2 Billion,” December 7, 2005.

[27] *PJM Settlement Agreement Filing*, Docket Nos. EL03-236-006 and EL04-121-000 (Consolidated), November 16, 2005.

1.1.5. *Administrative Scarcity Pricing*

Hot conditions in the summer of 2005 created transmission flow patterns that induced PJM to dispatch generators out-of-merit order in the Mid-Atlantic Region. Consequently, PJM was unable to use the market mechanism to assure power balance on two occasions.[28] These events led PJM "to implement an administrative scarcity pricing mechanism to ensure the appropriate tradeoff between limiting local market power and market prices that reflect scarcity conditions,"[29] where "scarcity conditions" are defined as occurring when:

- supply is less than load plus required operating reserves;
- emergency actions are needed in two or more contiguous zones; and
- scarcity is created by congestion on transmission facilities at 500 kV or higher.

Emergency actions include emergency energy request events (when PJM asks for emergency energy purchases), maximum emergency generation events (when generators are asked to provide output greater than their normal economic limits), voltage reductions (when distribution-level voltages are reduced by 5%), and rotating blackouts.

When such scarcity conditions occur, scarcity pricing will be implemented in "Scarcity Pricing Regions," which are areas that have the potential to be import-constrained due to limitations in facilities at 500 kV and higher. When scarcity pricing is triggered, the price in the Scarcity Pricing Region will be set equal to the highest market-based offer price of all generating units operating under PJM direction to supply either energy or reserves on a real-time dispatch basis in that region. No offer capping for transmission constraints may be initiated or continued in the Scarcity Pricing Region (except for the overall offer cap of $1,000 per MWh) while scarcity pricing is in effect. In addition, if a generator outside a Scarcity Pricing Region is called upon to relieve the transmission constraint that caused the scarcity condition, then during the time that the scarcity pricing is in effect in that Scarcity Pricing Region, that generator will be paid the higher of the scarcity price for the Scarcity Pricing Region or the price that it otherwise would have been paid under PJM's market rules; but that generator's offer price will not set LMPs or scarcity prices in the Security Pricing Region.

1.2. Midwest ISO

The major developments in Midwest ISO include: a) the introduction of LMP markets; b) the development of seams agreements; c) changes in Midwest ISO membership; and d) improving market design. Each of these is discussed in turn below.

1.2.1. *Introduction of LMP Markets*

The Midwest ISO began operating in February 2002, and began its Day 2 Market in April 2005. A key feature of the Day 2 Market is its locational marginal price (LMP) for energy, by which the price of energy may be different at each power system location (node). The Day 2 Market

[28] PJM 2005 SOM, pp. 29-30.

[29] PJM 2005 SOM, p. 145.

does not include markets for ancillary services, such as regulation and reserves, though such markets may be added later.

1.2.2. Seams Agreements

Inconsistencies and barriers to trade among RTO markets affect the efficiency of the Midwest ISO market. "There were a number of hours exhibiting large price differences between the Midwest ISO and adjacent markets that were accompanied by sub-optimal interchange between the markets."[30] Consequently, the Midwest ISO has entered into or is presently consummating a series of seams agreements with the several RTOs and reliability authorities with which it shares common borders. The agreements particularly concern data exchange and congestion management processes. The neighboring authorities are the PJM, the Tennessee Valley Authority, the Mid-Continent Area Power Pool, and the Southwest Power Pool.[31]

Midwest ISO's Independent Market Monitor (IMM) finds that prices at the borders between Midwest ISO and its neighbors "are relatively well arbitraged…,"[32] which implies consistent and efficient system dispatch by Midwest ISO and its neighbors. On the other hand, the IMM finds that trades between the Midwest ISO and Ontario markets "do not appear to be highly responsive to the price difference between the two markets."[33] The IMM also finds that unannounced last-minute changes in external trades have forced Midwest ISO "to commit additional generation and rely more heavily on peaking resources."[34]

The Joint Operating Agreement (JOA) with PJM is described in 2.1.1. The IMM recommends that the JOA be extended to optimize the net interchange between the two areas. The participants' transactions would, therefore, be purely financial and the RTOs would determine the optimal physical interchange based on the relative prices in the two areas. This change would achieve the vast majority of any potential savings associated with jointly dispatching the generation in the two regions."[35]

1.2.3. Changes in Membership

During 2005, the Midwest ISO gained one vertically integrated transmission-owning member (Wolverine Power Supply Cooperative, Inc.). A standalone transmission company member (GridAmerica) split into three separate vertically integrated transmission-owning members (AmerenUE and Ameren CIPS, American Transmission Systems, Inc., and Northern Indiana Public Service Company). The Midwest ISO also had a net gain of ten non-transmission owning members.

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[30] Midwest ISO 2005 SOM, p. ix.

[31] Midwest ISO 2004 Annual Report, p. 6.

[32] Patton, Midwest ISO 2005 SOM Presentation, p. 15.

[33] Patton, Midwest ISO 2005 SOM Presentation, p. 163.

[34] Patton, Midwest ISO 2005 SOM Presentation, p. 163.

[35] Patton, Midwest ISO 2005 SOM Presentation, p. 15.

Meanwhile, one Midwest ISO member has been engaged in the process of withdrawing from the RTO. On March 17, 2006, FERC approved the proposal of Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) to withdraw from the Midwest ISO.[36] LG&E and KU were motivated to withdraw from Midwest ISO principally by a desire to satisfy FERC Orders 888 and 889 in a less expensive manner than through membership in an RTO. LG&E and KU presented FERC with studies they had conducted of the costs and benefits of membership in Midwest ISO relative to various non-RTO alternatives; and these studies showed at least one non-RTO option made the companies and their customers better off. The Midwest ISO also presented studies that showed the opposite.

Other utilities have also given notice of their intentions to withdraw. In December 2005, Minnesota Power Company filed notice with FERC of its intention to withdraw from the Midwest ISO at the end of 2006. In this case, the notice was not motivated by dissatisfaction with the Midwest ISO but was instead motivated by a decision of the Minnesota Public Utilities Commission (MPUC) that threatens to deny Minnesota's utilities the right to recover certain costs of doing business within the Midwest ISO. Xcel Energy also considered giving such notice, but declined to do so in the hope that a suitable state regulatory agreement might be forthcoming upon reconsideration of the MPUC's December order. Also in December, Southern Illinois Power Cooperative filed a notice of its intent to withdraw from Midwest ISO in 2006, citing costs outweighing perceived benefits as its principal motivation. In response to these withdrawal threats, the Midwest ISO engaged in negotiations in Minnesota that have significantly mitigated the concerns of the Minnesota utilities and regulators.

1.2.4. Improving Market Design

The Midwest ISO Day 2 market has had several design problems that have manifested themselves in the forms of high costs and system control issues. In response to these problems, the IMM has made several recommendations.[37] Some of the recommendations aim to improve the efficiency of system commitment and dispatch:

- Prospectively mitigate physical offer parameters that limit generator flexibility. (See Section 3.2.1.)
- Allow Midwest ISO operators to dispatch the full reserve range on units. (See Section 3.2.1.)
- Implement a "look-ahead" capability to improve CT commitment and better manage the ramping capability of slow-ramping units.
- Relieve transmission constraints through re-dispatch of all units that can relieve the constraints.

Some of the recommendations aim to improve the quality of energy prices:

- Allow CTs that run at their minima or maxima to set energy prices. (See Section 3.2.1.)

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[36] Federal Energy Regulatory Commission, *Order Conditionally Approving Request To Withdraw From The Midwest ISO*, Docket Nos. EC06-4-000 *et al*, March 17, 2006.

[37] Patton, Midwest ISO 2005 SOM Presentation, pp. 18-19.

- Set nodal prices using constraint penalty factors when a transmission constraint is unmanageable.

One recommendation recognizes that Midwest ISO is missing markets:

- Develop real-time ancillary services markets. (See Section 3.2.2.)

Midwest ISO is in the process of studying how best to implement many of these recommendations.

1.3. Third ISO

2. MARKET DESIGN, STRUCTURE, AND PERFORMANCE

This section describes the market design, structure, and performance of RTOs' energy, regulation, reserve, and capacity markets. "Market design" refers to the rules and procedures by which markets are supposed to work. "Market structure" refers to distribution of resources and obligations among market participants, particularly the ownership of productive facilities. "Market performance" refers to the efficiency with which markets have actually delivered services to consumers.

Market design and structure provide a basis for predicting the likelihood that markets will operate efficiently. This is important for assessing the competitiveness of those markets (bilateral markets and FTR markets) in which it may be difficult to assess the conduct of market participants. In addition, understanding market design and structure provides a foundation for assessing whether consumers are likely to receive net benefits from the creation and operation of these markets by RTOs. Quite often there exists a gap between theoretical predictions and what actually takes place within the implementation of a particular design, simply because there are limitations on the efficiency gains that can be achieved in practice.

The actual performance of a market can be measured partly by price trends and partly by the relationship between the market-clearing price and marginal cost. In general, stable or falling prices are good, and prices that approximate marginal costs are good. Nonetheless, rising electricity prices may not indicate a performance problem if fuel prices are rising; and recovery of fixed costs requires that prices sometimes exceed marginal costs.

If an electricity market administered by an RTO is efficient, retail consumers could expect to see electricity prices that reflect the efficient dispatch of generation to meet load, including the efficient management of congestion. In theory, this dispatch will be less costly than any other dispatch of power; and the cost savings should ultimately be enjoyed by consumers in the form of lower bills than they would receive otherwise. Whether these benefits are realized by consumers, however, depends to a degree on state regulation of retail rates. If retail rates are frozen or rates are otherwise not permitted to reflect the spot prices for power, then the benefits to consumers may be reduced and non-existent.

For conceptual convenience, "efficiency" is often divided into short-term efficiency and long-term efficiency. "Short-term efficiency" refers to the question of whether power system resources and demand-side resources are committed and dispatched so as to serve load at least cost, given fixed stocks of generation and transmission capital. In other words, short-term efficiency is a measure of whether costs are being minimized over periods of months, weeks, days, hours, and minutes. "Long-term efficiency" refers to the question of whether generation, transmission, and demand-side investments are being undertaken in quantities and locations that minimize power system costs over periods of years. Most assessments of power market efficiency look only at short-term efficiency, and therefore take the transmission system configuration and deliverability as given. This "short-term focus" has clearly led to significant infrastructure issues in the development and delivery of long-term power supplies.

While a particular RTO's market design may be conducive of efficient market performance, market participants may not all receive the benefits of that performance in the same proportion to the costs that they bear. It is likely that, for a given RTO, some market participants may be net losers while other market participants may be net gainers. Identifying net winners and net losers within a particular RTO and measuring the gains and losses are extremely difficult. Consequently, the distribution of the benefits and costs of RTOs and their markets is discussed conceptually in this issue of the Report Card. Future Report Cards may be in a better position to provide measurement of the winners and losers within the RTO markets.

In this section, the discussion of each RTO is organized by product market. We describe each product market's design, look at each product market's structure, and then examine price trends. We conclude by assessing the behavior of generation firms.

2.1. PJM

PJM currently provides energy, regulation, and spinning reserve services through market-based mechanisms, though bids for spinning reserves are largely required to be cost-based. A generation unit can simultaneously provide energy, regulation, and spinning reserve services from different portions of its capacity. Consequently, these three markets are cleared simultaneously and co-optimized to minimize the cost of the combined products.

PJM provides scheduling and dispatch, voltage control, and supplemental reserve services on a cost basis. PJM also has a market for capacity, though this is not actually a service.

This section describes PJM's energy, regulation, spinning reserve, and capacity markets.

2.1.1. Energy Markets

This section describes the design, structure, and performance of PJM's energy markets.

2.1.1.1. Market Design

The PJM Energy Market comprises all energy transactions, including the sale or purchase of energy in Day-Ahead and Real-Time Energy Markets, bilateral and forward markets, and self-supply. Market participants can buy and sell energy in any and all of these markets. Purchases may be made from generation located within or outside PJM. Generation owners can sell their output within PJM or externally; and they can use generation to meet their own loads, to sell into the spot market, or to sell bilaterally. Market participants can use incremental and decremental bids in the Day-Ahead Energy Market to hedge positions or to arbitrage expected price differences between markets.

PJM limits the exercise of market power through the imposition of "offer caps," which are the maximum prices that sellers can bid on the power that they offer to the Real-Time and Day-Ahead Energy Markets. There is an overall offer cap of $1,000 per MWh that is applicable to all sellers at all times. PJM also imposes offer caps on individual generators when transmission congestion creates "a structurally noncompetitive local market"[38] and PJM believes that such generators could raise market prices above competitive levels. Generators subject to offer capping receive either the market price or their bid price, whichever is higher.

Two types of generators receive special treatment with respect to offer capping. First, certain "grandfathered" generators are partly exempt from offer capping because their construction depended on PJM's earlier exemption from offer capping. Second, generators that were offer-capped in more than 80% of their run hours in the previous year are eligible to receive additional payments to facilitate their cost recovery. These additional payments are either: a) the greater of a 10% or $40 per MWh adder; or b) generator-specific going-forward costs.[39]

2.1.1.2. Market Structure

Market structure is usually assessed according to various measures of how either generation ownership or electricity sales are distributed among suppliers. Two types of measures are particularly popular: the Herfindahl-Hirschman Index (HHI); and pivotal supplier indexes. We also look at ownership patterns for marginal units.

<u>Herfindahl-Hirschman Index</u>

The Herfindahl-Hirschman Index (HHI) is a measure of industry concentration—that is, the extent to which supply is controlled by a small number of suppliers.[40] FERC has adopted the interpretation of market concentration statistics of the *Horizontal Merger Guidelines*,[41] which posit that markets can be broadly characterized as *unconcentrated* when the HHI is below 1,000 (equivalent to 10 firms with equal market shares), *moderately concentrated* when the HHI is between 1,000 and 1,800; and *highly concentrated* which the HHI is greater than 1,800 (equivalent to about six firms with equal market shares). High HHIs indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High HHIs indicate an increased potential for sellers to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that sellers cannot exercise market power.

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[38] PJM 2005 SOM, p. 87.

[39] PJM 2005 SOM, p. 93.

[40] HHI is calculated by summing the squares of seller market shares in whole percentages. For example, if a market has three sellers with shares of 25%, 35%, and 40%, respectively, the HHI would equal $25^2 + 35^2 + 40^2 = 3,450$. HHIs range in value from near 0 (when there are numerous suppliers with small market shares) to 10,000 (when there is a single supplier with a 100% market share).

[41] United States Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, April 2, 1992, *reprinted in* 4 Trade Reg. Rep. (CCH) ¶ 13,104.

Table 1 summarizes the HHIs for the last phases of 2004 and 2005. Table 1 shows the minimum, average, and maximum observed HHIs. The statistics in Table 1 show that the PJM market as a whole is moderately to highly concentrated. The base of the dispatch stack is on average moderately concentrated, while the intermediate and peak sections are highly concentrated. This market structure has characterized PJM for several years, though the declining trend in HHIs for 2004 and 2005 indicates that concentration has fallen as PJM has expanded.

Table 1
PJM Energy Market Concentration Indexes
Herfindahl Hirschman Indexes[42]

Period		Base	Intermediate	Peak	Total
Phase 3 (2004)	Maximum	2,001	6,352	10,000	1,788
	Average	1,762	3,761	5,294	1,448
	Minimum	1,522	1,590	931	1,164
Phase 5 (2005)	Maximum	1,593	8,257	10,000	1,565
	Average	1,362	2,793	4,437	1,200
	Minimum	1,232	731	717	855

According to PJM:

> "Analysis of the PJM Energy Market indicates moderate market concentration overall. Further, analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments. Analysis also indicates that the ComEd Control Area was highly concentrated overall and in each segment of the supply curve. Several other geographic areas of PJM exhibited moderate to high levels of concentration when transmission constraints defined local markets."[43]

Note that the statistics in Table 1 ignore transmission constraints within PJM. In other words, these statistics assume that generators in any part of PJM can compete with generators in any other part of PJM. Because transmission constraints in fact limit the geographic scope of each generator's ability to compete, the situation is less competitive than indicated by the table. If it were possible to divide PJM into sensible subregional markets,[44] those submarkets would very likely be more concentrated than indicated by Table 1. These concentration problems arise when the transmission system becomes constrained.

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[42] PJM Interconnection, L.L.C., Market Monitoring Unit, *2004 State of the Market*, March 8, 2005 (hereinafter the "PJM 2004 SOM Report) and PJM 2005 SOM Report, Base, Intermediate and Peak columns from Table 2-6, p. 61 and Total column from Table 2-5, p. 60.

[43] PJM 2004 SOM Report, p. 24.

[44] Because transmission constraints can change from hour to hour, PJM's submarkets can change from hour to hour. Because loop flows often allow generators to partially compete to serve load on the other side of transmission constraints, the placement of generators within submarkets is often not black and white, but is instead subject to shades of gray.

Pivotal Supplier Index

Pivotal supplier indexes examine the possibility that, under some power system conditions, the capacity of a single generation owner may become critical to meeting market demand. In principle, such a "pivotal" generation owner can withhold supply and drive prices up without limit. One measure of pivotal supply is the Residual Supply Index (RSI).[45] A generation owner is a pivotal supplier when its RSI is less than 1.0; and it is not pivotal otherwise. The RSI is not a bright line test, however: while an RSI less than 1.0 clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. For example, two suppliers could be jointly pivotal.

Table 2 summarizes the average and minimum overall RSI values for the last phases of 2004 and 2005, as well as the number of hours the RSI fell below 1.10 and 1.00. RSI summary statistics are also provided for the two largest generation owners together.

Table 2
PJM Energy Market Residual Supplier Index[46]

Period		Average RSI	Minimum RSI	% of Hours RSI < 1.10	% of Hours RSI < 1.00
Phase 3 (2004)	**Single Supplier**	1.67	1.14	0.0%	0.0%
	Two Suppliers	1.34	0.90	6.2%	1.0%
Phase 5 (2005)	**Single Supplier**	1.52	0.97	4.5%	0.4%
	Two Suppliers	1.27	0.80	25.5%	13.9%

Table 2 shows a short-term trend of a growing frequency of both one-firm and two-firm pivotal supply. The average RSIs fell between 2004 and 2005, indicating a greater likelihood that one or two sellers might be able to create a shortage. Minimum RSIs also fell, and in 2005 were below the critical value of 1.00. RSIs were below 1.10—that is, approaching the critical value—with growing frequency between 2004 and 2005. RSIs were also below the 1.00 critical value with growing frequency. It may be a matter of some concern that two sellers could together create a shortage in 13.9% of the hours of Phase 5. Furthermore, because this analysis ignores transmission constraints, it fails to recognize the possibility—indeed, the probability—that there are many hours in which single suppliers may be pivotal in particular load pockets even if no supplier would be pivotal in the absence of transmission constraints.

On the other hand, it is not clear that the foregoing statistics really indicate a market power problem. Suppliers generally have load obligations that make it impossible (or at least unprofitable) for them to withhold supply. Consequently, the fact that a supplier is pivotal is not necessarily meaningful, as load obligations can substantially reduce a supplier's incentives to use its pivotal position to exercise market power.

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[45] The RSI is computed for a specific supplier in a market, and equals the ratio of: a) the available capacity or actual quantity bid into the market by all *other* suppliers (the residual supply); to b) the total market demand.

[46] PJM SOM 2005 Report, at Table 2-7 and Table 2-8, p. 68. The overall RSI value for PJM is equal to the RSI of the largest generator in the hour.

PJM has calculated RSI results for different regions of the PJM footprint. For the ComEd region in 2004, PJM states the following:

> "In the ComEd Control Area there were 2,287 hours, or 62% of the hours during Phase 2, when a generation owner was pivotal… The average RSI was 0.97 and the minimum was 0.64. The ComEd Control Area HHI market concentration results indicate that the market is highly concentrated… For the top two supplier analysis, all hours of Phase 2 had an RSI of less than 1.0… The results of the Energy Market overall, including ComEd, were competitive for 2004."[47]

The observation regarding "results" refers to PJM's conclusion that suppliers' behavior was competitive in spite of the high concentration of generation ownership.

The residual supply index (RSI) results for the Mid-Atlantic Region over the period from 2003 to 2005 have been more favorable than those for the ComEd market. The 2005 State of the Market Report observes the following:

> The RSI results…are consistent with the conclusion that PJM Energy Market results were competitive in both 2004 and 2005, with an average hourly RSI of 1.64 and 1.55, respectively. In 2005, a generation owner in the PJM Energy Market was pivotal for only 24 hours, less than 0.3 percent of all hours during the year. This represents an increase in pivotal hours from 2004, when a generation owner was pivotal in the Energy Market for eight hours, or less than 0.1 percent of all hours. [48]

For 2005, PJM only provided RSI results for the entire energy market footprint, and did not present separate RSIs for the ComEd control zone.

Ownership of Marginal Units

A third measure of market structure is the ownership of generating units that set the market-clearing price of energy. These units are those that, within each five-minute dispatch interval, are the "marginal" energy source in the senses that: a) they have the highest incremental running costs of all generators operating above minimum output levels; and b) they are the units that can most efficiently change output in response to changes in load levels. Because the energy price is typically determined (or strongly influenced) by the cost of generation of the marginal unit, the less often a single company owns the marginal unit, the less the potential for it to exercise market power.

The summary statistics presented in Table 3 show, for the years 2000 to 2004, the number of companies that owned a unit that was marginal for the stated percentage range of five-minute intervals. For example, in 2000, two companies each owned the marginal unit in 5%-10% of all 5-minute pricing intervals, two companies each owned the marginal unit in 10%-15% of the intervals, and three companies each owned the marginal unit in 15%-20% of the intervals. The most significant numbers are those that appear in the right-most columns because the companies with marginal generation in the most hours are those most likely to exercise market power. It is

[47] PJM 2004 SOM Report, p. 61.

[48] PJM 2005 SOM Report, p. 68. A similar statement can be found in the PJM 2004 SOM Report, p. 47

notable that there have been no companies with marginal generators more than 20% of the time except in 2004, when there was one such company. From 2001 onward, there have always been two companies with marginal units more than 15% of the time, which can be seen by summing the figures in the "15% to 20%" and "20% to 30%" columns. Similarly, except for the years 2000 and 2004, there have always been six companies with marginal units between 5% and 15% of the time, which can be seen by summing the figures in the "5% to 10%" and "10% to 15%" columns. On the whole, Table 3 confirms the HHI implication that there is moderate concentration; though the table by itself does not reveal whether this concentration is significantly changing over time.

Table 3[49]
Number of Companies Owning Marginal Energy Units in PJM

Year	Fraction of Time At the Margin			
	5% to 10%	10% to 15%	15% to 20%	20% to 30%
2000	2	2	3	0
2001	4	2	2	0
2002	4	2	2	0
2003	4	1	2	0
2004	6	0	1	1
2005	5	1	2	0

The top ten owners provided 77% of capacity and 84% of energy output in PJM in 2003. Seven of the top ten generation owners in PJM were regional utilities or their affiliates. Three of the top ten providers were independent power producers or utility affiliates that built or acquired generating assets outside of their traditional service territories.

The top ten utilities served 91% of peak load and 93% of total retail sales in the region. Many of the largest suppliers of retail load in PJM were also the largest owners of generation and were able to cover much of their load through self-supply.[50]

Table 4 shows PJM's daily average actual loads, day-ahead market volumes, and real-time market volumes, as well as some ratios among these figures. Furthermore, the table shows these figures averaged over all hours, peak hours, and off-peak hours. The figure shows that loads and trades rapidly increased over time with PJM's expansion, but that the ratio relationships held fairly steady.

2.1.1.3. Market Performance

Energy prices provide a direct measure of energy market performance. In markets with locational marginal prices (LMPs) and/or prices that vary hourly, it may be helpful to summarize LMPs and hourly prices through some price index. Although the overall level of prices is a good

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[49] PJM 2004 SOM Report, Table 2-16, p. 63 and PJM 2005 SOM Report, Table 2-9, p. 70.

[50] Similar information for 2004 and 2005 is not currently available.

general indicator of market performance and market competitiveness, price levels must be interpreted carefully because of the multiple factors that affect them.

Table 4
PJM Daily Average Spot Market Loads (MW), 2003 – 2005[51]

	2003	2004	2005
Daily Averages:			
Actual Loads (MW)	37,784	49,941	78,059
Day-Ahead Market Volumes (MW)	13,588	15,664	28,831
Real-Time Market (MW)	15,114	17,479	31,536
Day-Ahead / Real-Time	90%	90%	91%
Real-Time Market / Actual	40%	35%	40%
Daily Peak Averages:			
Actual Loads (MW)	NA[52]	NA	87,242
Day-Ahead Market Volumes (MW)	14,394	17,618	32,727
Real-Time Market Volumes (MW)	16,188	19,668	35,333
Day-Ahead / Real-Time	89%	90%	93%
Real-Time Market / Actual	NA	NA	41%
Daily Off-Peak Averages:			
Actual Loads (MW)	NA	NA	70,214
Day-Ahead Market Volumes (MW)	12,886	13,956	25,289
Real-Time Market Volumes (MW)	14,177	15,567	28,226
Day-Ahead / Real-Time	91%	90%	90%
Real-Time Market / Actual	NA	NA	40%

Table 5 shows that prices are generally higher in constrained hours than in unconstrained hours. It also shows a rising price trend during the period 2003-2005, with prices rising more sharply in constrained hours.

Table 5
Load-Weighted Average LMPs During Constrained and Unconstrained Hours in PJM ($/MWh) [53]

	Unconstrained Hours			Constrained Hours		
	2003	2004	2005	2003	2004	2005
Average LMPs	$34.69	$40.79	$44.00	$45.41	$45.83	$67.33
Median LMPs	$25.00	$36.62	$36.80	$41.29	$41.80	$57.13

Table 6 shows that locational prices have generally risen over the period 1998 through 2005. In recent years, for example, average LMPs rose by 7.5% between 2003 and 2004 and by 43.1% between 2004 and 2005. The prime reason for the recent increase has been the dramatic rise in

[51] PJM 2004 SOM Report, p. 23 and PJM 2005 SOM Report, p. 94.

[52] Not Available.

[53] PJM 2004 SOM Report, Table C-5, p. 296 and PJM 2005 SOM Report, Table C-9, p. 397.

natural gas prices. According to PJM, the "fuel-cost adjusted, load-weighted, average LMP was 4.2% lower in 2004 than in 2003" and "was 1.5 percent higher in 2005 than in 2004."[54] According to the Energy Information Administration's gas price for electricity production series, gas prices rose by 9% from 2003 to 2004 and by 34.9% from 2004 to 2005, which more or less corroborates PJM's figures for fuel-cost adjusted LMPs.[55]

Table 6
PJM Load-Weighted Average LMPs[56]

	Load-Weighted Average LMP ($/MWh)			Year-to-Year Changes	
Year	**Average**	**Median**	**Standard Deviation**	**Average LMP**	**Median LMP**
1998	$24.16	$17.60	$39.29	N/A	N/A
1999	$34.07	$19.02	$91.49	41.0%	8.1%
2000	$30.72	$20.51	$28.38	-9.8%	7.8%
2001	$36.65	$25.08	$57.26	19.3%	22.3%
2002	$31.58	$23.40	$26.73	-13.8%	-6.7%
2003	$41.23	$34.95	$25.40	30.6%	49.4%
2004	$44.34	$40.16	$21.25	7.5%	14.9%
2005	$63.46	$52.93	$38.10	43.1%	31.8%

Consistent with the foregoing trend in average prices, there has been a rising trend in the frequency with which prices reach high values. Although only five hours in 2004 saw average prices above $150 per MWh, there were 234 such hours in 2005.[57]

Figures 1 through 4 present descriptive information about the load-weighted average LMPs for the years 1998 through 2005, real-time and day-ahead market average prices by pricing zone for 2003 to 2005, and the ratio of real-time average prices to day-ahead average prices for 2003 to 2005. Figures 2 through 4 again illustrate the impact of the rise in natural gas prices over the past three years.

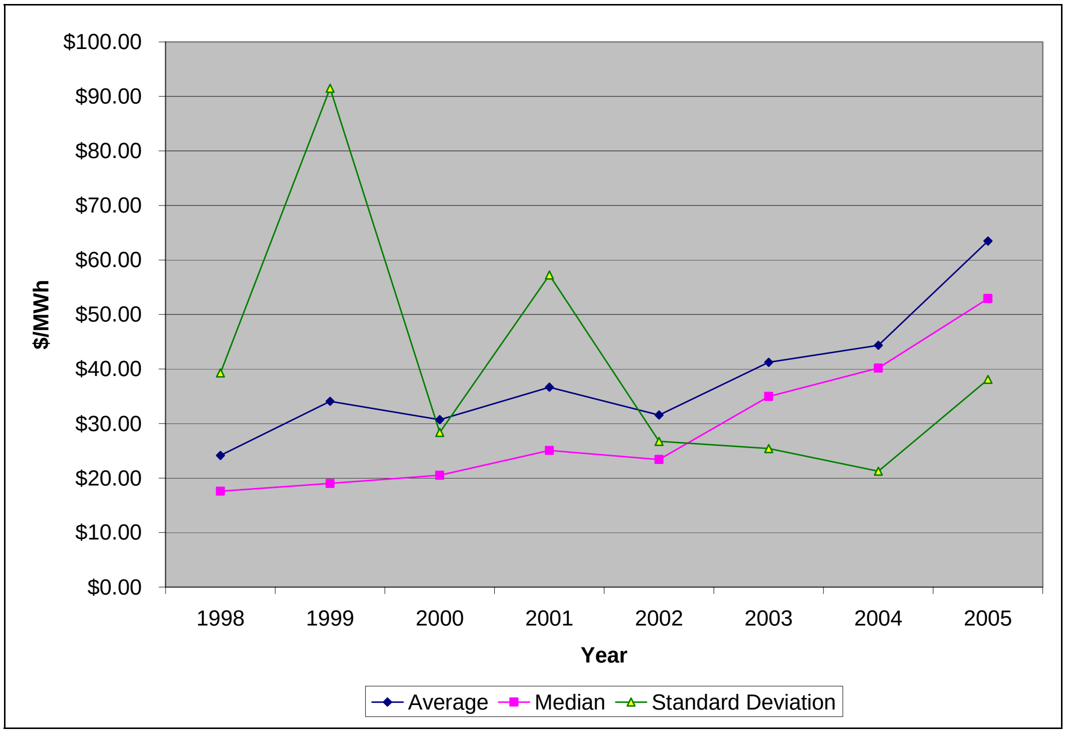
[54] PJM 2004 SOM Report, p. 48 and PJM 2005 SOM Report, pp. 27-28.

[55] The natural gas price percentage increase for 2005 relative to 2004 is based on the U.S. Natural Gas Electric Power Price series constructed by the Energy Information Administration. The percentage is based on a comparison of natural gas prices for gas used in the production of electricity for the eleven months January through November of 2004 and 2005 because the value of the series for December 2005 is unavailable. The series can be found at http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm .

[56] PJM 2004 SOM Report, Table 2-49, p. 106 and PJM 2005 SOM Report, Table 2-34, p. 104.

[57] PJM 2005 SOM Report, p. 28.

Figure 1
PJM Load-Weighted Average LMP
1998 – 2005[58]



One interesting feature of Figure 1 (which is also shown in Table 6) is that the standard deviation of the load-weighted LMPs has been trending downward—unevenly—over the past several years. This is an indication that the PJM market price is becoming less volatile over time. Lower price volatility is generally a good thing because it indicates the degree of market risk that must be hedged. Market risk management entails costs that are ultimately incorporated into the delivered commodity price. Thus, in principle, lower price volatility should translate into lower prices, all else equal.[59]

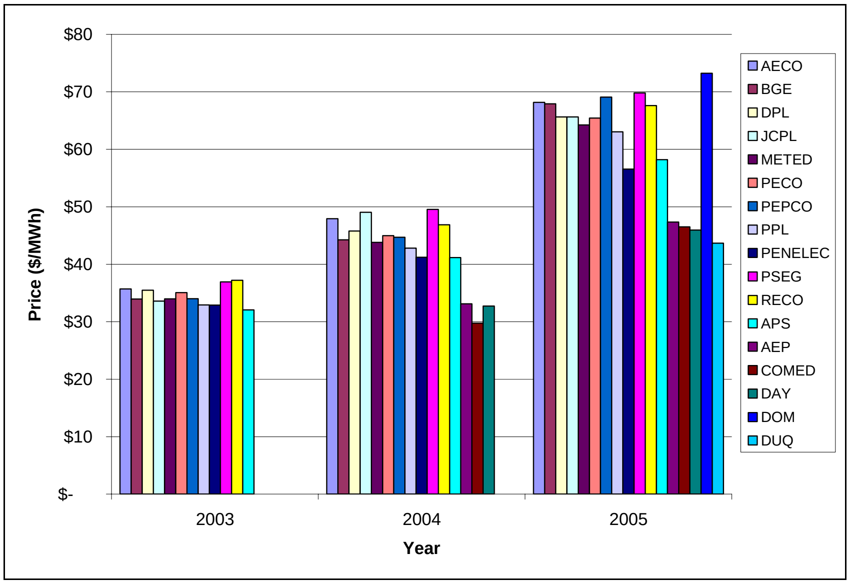
Figures 2 and 3 show the trend in the separation of prices across zones for both real-time and day-ahead LMPs. The average LMPs for the new PJM companies are significantly below the LMPs for the classic PJM companies in the Mid-Atlantic Region. This difference reflects that fact that PJM's power generally flows from the west (where there tends to be surplus capacity of relatively low-cost nuclear and coal-fired power) to the east (where there are the high loads of the seaboard metropolises and gas- and oil-fired units are frequently on the margin). Because integration of the six new utilities into the PJM footprint increased power flows among formerly separate control areas, integration can be expected to both raise LMPs for those newly integrated

[58] PJM 2004 SOM Report, Table 2-49, p. 106 and PJM 2005 SOM Report, Table 2-34, p. 104.

[59] Figures 7 and 8, which appear later in the text, provide information on price volatility in real-time and day-ahead markets, respectively. These figures indicate that real-time price volatility has generally declined over the period 2003 to 2005, and that day-ahead price volatility declined from 2003 to mid-2004 but returned to the early 2003 levels by 2005.

utilities in the west and lower LMPs in the east. Of course, transmission constraints limit such equalization of prices between the western and eastern divisions.

Figure 2
PJM Annual Average Real-Time Market Prices by Zone
2003 – 2005[60]



As shown in Figure 4, the ratio of average real-time (RT) to average day-ahead (DA) market prices suggests that the relationship between the RT prices and DA prices reversed between 2003 and 2004 and then reversed again (in the opposite direction) between 2004 and 2005. For example, in 2004, before the expansion was completed, the RT prices on average run about 1% to 2% higher than DA prices for the eastern division, while in 2005 RT prices averaged about 1% to 2% below DA prices. This reversal may merely indicate a healthy market: if RT prices are sometimes a little higher than DA prices and sometimes a little lower, there is arguably a lack of bias in the DA prices.

The correlation coefficient between average RT and average DA prices is 0.99 for each of the years 2003 to 2005. This high coefficient is further evidence that DA prices are good predictors of RT prices.

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[60] PJM LMP data obtained from PJM website.

Figure 3
PJM Annual Average Day-Ahead Market Prices by Zone
2003 – 2005[61]

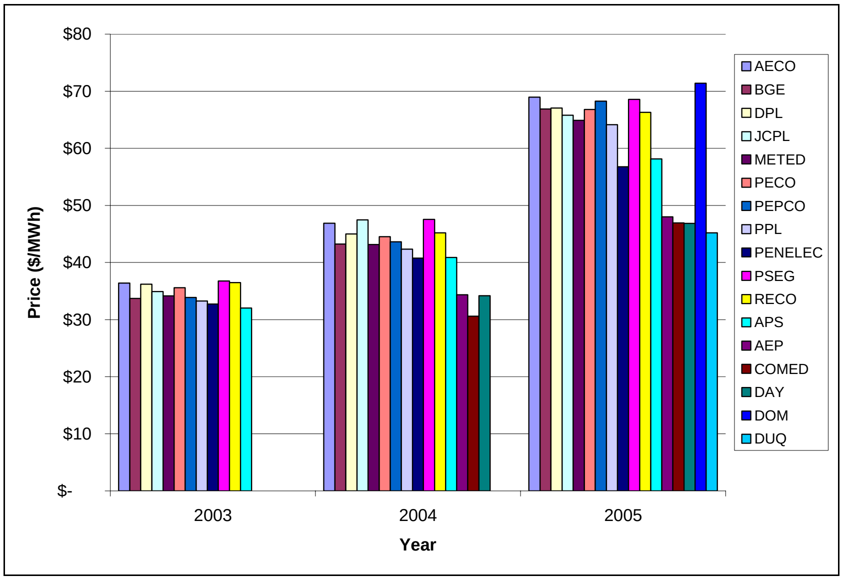
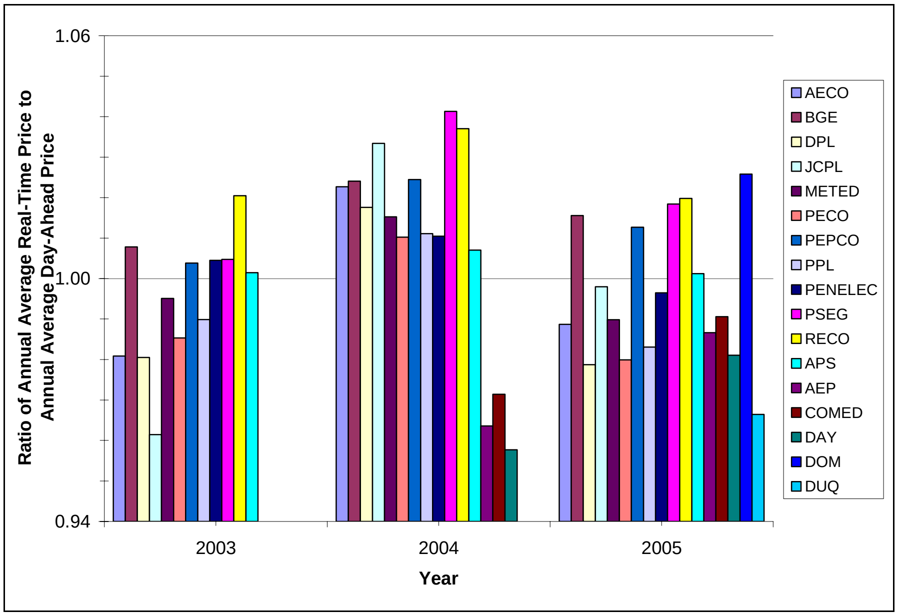


Figure 4
PJM Ratio of Average Real-Time to Average Day-Ahead Market Prices by Zone
2003 – 2005[62]

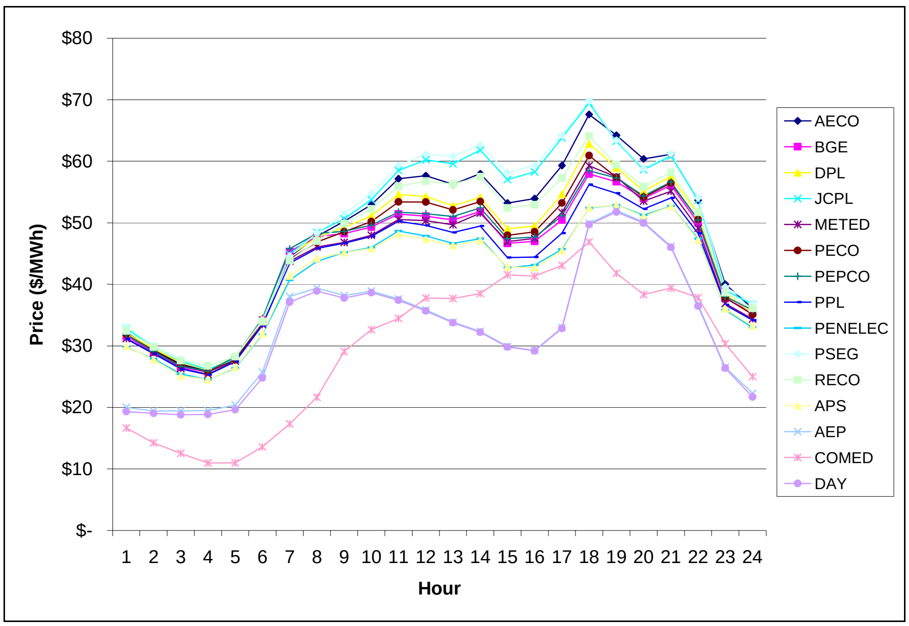


[61] PJM LMP data obtained from PJM website. The 2003 data are for the partial year starting on May 1.

[62] Based on real-time and day-ahead prices obtained from PJM website.

Figures 5 and 6 show the average hourly real-time LMPs by zone for 2004 and 2005, respectively. The figures show that the separation among average zonal prices grew from 2004 to 2005. The western region prices, comprised of AEP, ComEd, DAY, DUQ, and APS, are consistently lower than the eastern and southern region prices. This separation is due primarily to the fact that demand (large population centers and industrial activity) is higher in the eastern and southern regions and the less expensive generation is located in the western region of PJM. Transmission constraints impede flows from west to east meaning that higher cost generation in the eastern and southern regions must be dispatched to satisfy demand. If there were no transmission constraints, the unconstrained transmission flows would be expected to reduce or eliminate the differences among the zonal prices. However, the separation in zonal prices between the western and eastern region prices suggests that the growing transmission congestion and losses prevent this gap from closing. The total congestion cost in PJM in 2005 was $2.1 billion.

Figure 5
PJM Annual Average Hourly Real-Time Price by Zone
2004[63]



Figures 7 and 8 show the trends in the volatility of PJM zonal LMPs in the real-time and day-ahead markets. Volatility is measured as the standard deviation of the percentage change in monthly average on-peak real-time and day-ahead LMPs. The measure presented in Figures 9 and 10 represents a 12-month rolling average of monthly percentage price changes. Both figures show that LMPs were most volatile in 2003, with volatility declining sharply at the end of 2003 and then slowly rising in 2004. One explanation for the lower volatility in 2004 was the fact that the summer of 2004 was mild in comparison to the average summer.

[63] PJM LMP data were obtained from PJM website.

Figure 6
PJM Annual Average Hourly Real-Time Price by Zone 2005[64]

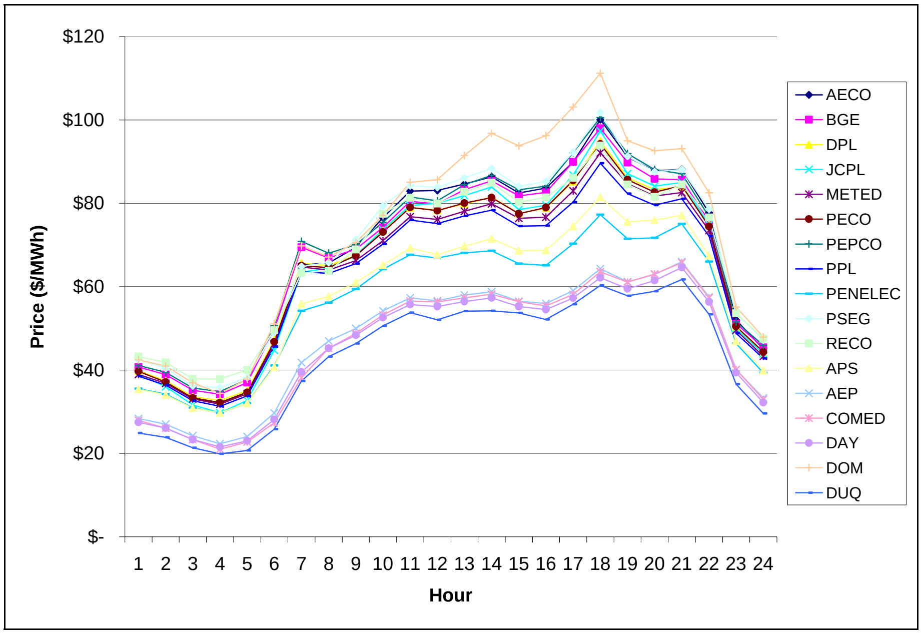
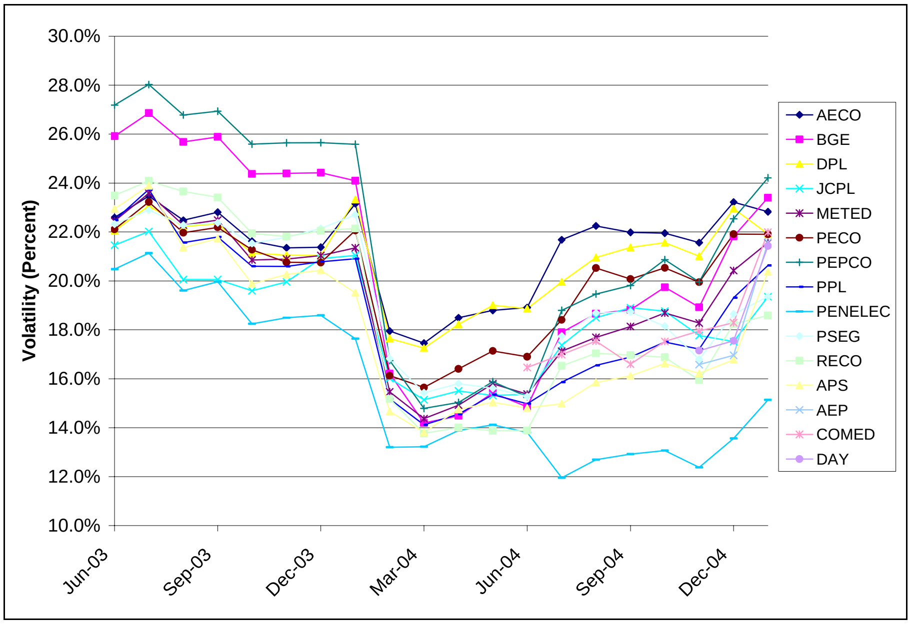


Figure 7
PJM Zonal Real-Time LMP Volatility, 2003 to 2005[65]



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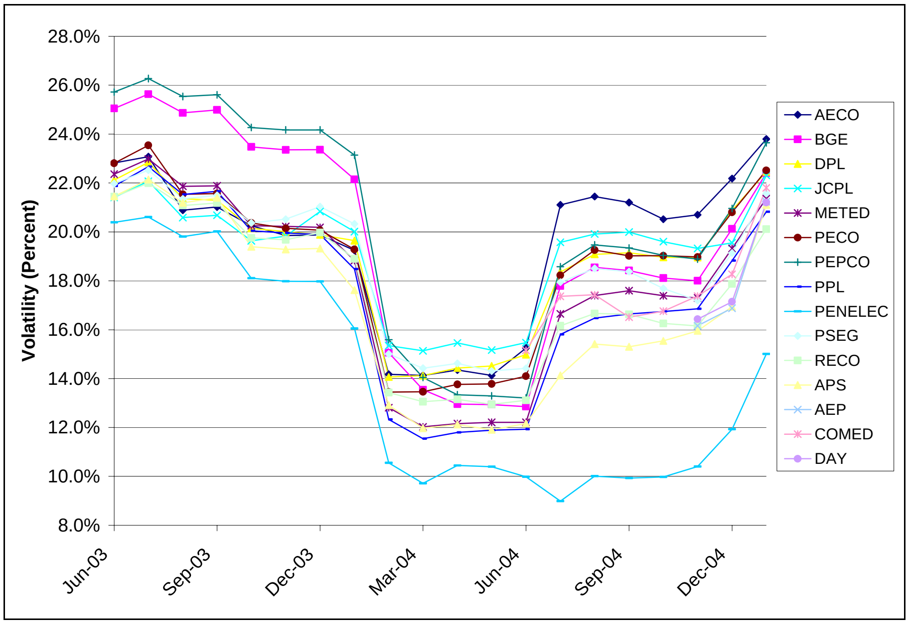
64 PJM LMP data were obtained from PJM website.

65 Derived from PJM LMP data.

Figure 8
PJM Zonal Day-Ahead LMP Volatility, 2003 to 2005[66]



To limit the exercise of market power, PJM has placed caps on the offers of many generating units. Table 7 shows the frequency of offer caps—in hours and in MWs—during the years 2001 through 2005. There appears to be a downward trend, most likely due in great degree to the rising level of excess generating capacity in the same period. In 2005, there were 40 generating units that received additional compensation because of the frequency with which their bids were capped. All of these units are located to the east of the Central Interface.[67]

Table 7
Annual Offer Capping Statistics, 2001 to 2005[68]

Year	Real Time		Day Ahead	
	Hours Capped	MW Capped	Hours Capped	MW Capped
2001	2.8%	1.0%	2.8%	0.7%
2002	1.6%	0.3%	0.7%	0.1%
2003	1.1%	0.3%	0.4%	0.2%
2004	1.3%	0.4%	0.6%	0.2%
2005	1.8%	0.4%	0.2%	0.1%

Overall, the MMU has concluded that PJM's Energy Markets were competitive in 2004 and 2005; but the MMU has serious concerns about the future. The fundamental problem is that PJM's Energy Market is concentrated, meaning that there is a significant potential for the

[66] Derived from PJM LMP data.

[67] PJM 2005 SOM Report, p. 93.

[68] PJM 2005 SOM Report, Table 2-20, p. 88.

exercise of market power. The MMU finds that market power was not exercised in 2004 and 2005 because of generator obligations to serve load, supply that was generally in surplus relative to demand, and PJM's mitigation of local market power. But the MMU notes that, "Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market."[69]

2.1.2. Regulation Service Markets

Order No. 888 requires that transmission providers offer "Regulation and Frequency Response Service," which we refer to as "Regulation Service." This service addresses very short-term, second-to-second imbalances between generation and load by moving the output of selected generators up and down via an automatic generation control (AGC) signal. The ability of generators to provide this service varies substantially by generation technology, with the best responses generally available from hydro and gas-fired facilities, as well as from some coal-fired facilities with AGC equipment.

This section describes the design and structure of PJM's regulation market. It examines the concentration of regulation markets and the implications for the exercise of market power. It also provides a history of observed regulation prices.

2.1.2.1. Market Design

PJM's regulation market is divided into regions that have changed over time as PJM has expanded. The original PJM footprint, prior to when Allegheny Power (AP) joined PJM in 2002, is the Mid-Atlantic Region. When Allegheny Power joined, the regulation market had two regions: the Mid-Atlantic Region and the Western Region, the latter of which included solely the AP Control Zone. This regional definition persisted through Phase 1 of the PJM expansion. In Phase 2, a third regulation region was added for the ComEd Control Area. In Phases 3 through 5a, PJM returned to having two regulation regions: the original Mid-Atlantic Region; and a Western Region comprised of the remaining Control Zones. In Phase 5b (beginning in August 2005), PJM created an experimental Combined Regulation Market that encompasses all of PJM.

The Regulation Market in the PJM Mid-Atlantic Region was cleared based on participants' bids during all phases, though bids have been subject to a $100 per MWh offer cap. All suppliers have been paid the market-clearing prices, which depend upon an as-bid supply curve and a PJM-defined demand curve. The supply curve is comprised of two components: generators' bids that indicate the MW and prices of their regulation offers; and PJM's calculation of unit-specific opportunity costs of foregone energy sales.

During Phases 1 through 4, Regulation Markets outside of the Mid-Atlantic Region were priced on a cost basis because of concerns that these markets are not structurally competitive: in some cases, there has been only a single regulation supplier in these other markets. In Phases 1 and 2 of 2004, in the AP Control Zone, regulation prices were based on unit-specific costs plus unit-

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[69] PJM 2005 SOM Report, p. 28. Also see PJM 2005 SOM Report, p. 23, and PJM 2004 SOM Report, p. 24 and p. 53.

specific opportunity costs because there was only one supplier of regulation in the zone.[70] For Phase 3, each regulating unit in the AP zone was compensated on the basis of unit-specific cost-based offers plus unit-specific opportunity costs.[71] In the Western Region, regulation prices were based on unit-specific incremental costs and opportunity costs plus a margin of $7.50 per MWh. During Phase 5, the Regulation Markets outside of the Mid-Atlantic Region have depended upon a combination of market-based and cost-based bids, with Dominion and AEP required to make cost-based offers because of their dominant market positions.

2.1.2.2. Market Structure

Table 8 summarizes the minimum, average, and maximum HHI values for various phases of 2004 and 2005. The values of the RSI for the same time periods and regions are presented in Table 9. Table 10 shows the frequency with which 1, 2, or 3 suppliers are pivotal. All of these statistics—HHIs, RSIs, and pivotal supply—are computed on the basis of the regulation offered and eligible.[72] The basic story is that the Regulation Market is concentrated when it is divided into separate subregions of PJM, but is almost unconcentrated when all of PJM is integrated into a single market. Because the geographic scope of regulation service is arguably not limited by transmission constraints, it makes sense to have a single Regulation Market for the whole PJM footprint, with a corresponding benefit for competition.

Table 8[73]
PJM Regulation Market Concentration Indexes
HHIs

Region	Year	Phase	Minimum	Average	Maximum
Mid-Atlantic	2004	1-3	1,088	1,608	2,770
	2005	4-5a	1,190	1,751	2,787
ComEd	2004	2	5,000	5,817	10,000
Western	2004	3	2,283	3,426	5,648
	2005	4-5a	1,757	2,802	4,810
All	2005	5b	866	1,079	1,562

[70] Unit-specific opportunity costs are the profits from the sale of energy that a particular generating unit foregoes by dedicating a part of its capacity to supplying regulation service rather than energy.

[71] PJM 2004 SOM Report, p. 179 and p. 188.

[72] *Offered regulation* may not be *eligible* for several reasons. In the PJM regulation market, the generator owner may declare that regulation is not available in certain hours. Additionally, the physical operating constraints of a unit may sometimes make it infeasible for a unit to provide regulation service.

[73] PJM 2004 SOM Report, Tables 5-1, 5-3, and 5-5, pp. 183-185; and PJM 2005 SOM Report, p. 42 and Tables 6-2, 6-6, and 6-10, pp. 260-264. Statistics are for “eligible” capacity.

Table 9[74]
PJM Regulation Market Residual Supplier Indexes

Region	Year	Phase	% of Hours RSI < 1.10	% of Hours RSI < 1.00	Average RSI	Minimum RSI
Mid-Atlantic	2004 2005	1-3 4-5a	6%	3% 7%	1.79	0.52
ComEd	2004	2	100%	100%	0.49	0.00
Western	2004 2005	3 4-5a	86%	78% 62%	0.95	0.59
All	2005	5b		1%		

Table 10[75]
Pivotal Supplier Statistics: Phases 4 and 5a

Region	Year	Phase	1 Pivotal Supplier	2 Pivotal Suppliers	3 Pivotal Suppliers
Mid-Atlantic	2005	4-5a	7%	48%	88%
Western	2005	4-5a	62%	100%	100%
All	2005	5b	1%	6%	29%

During 2004, the PJM Mid-Atlantic Region's Regulation Market had an average HHI of 1,608, which indicates the market is "moderately concentrated." Less than 3% of the hours had a single pivotal supplier. During Phases 1 and 2 of the year, there was only one supplier of regulation in the Western Region.

In Phase 2, the ComEd Control Area was a separate Regulation Market with an average HHI of 5,817, meaning that the market was highly concentrated. The average RSI of 0.49 confirms that this market was highly concentrated during Phase 2 of the expansion.

In Phase 3, the AP, ComEd, AEP, and DAY Control Zones became a single Regulation Market, with an average HHI of 3,426, indicating that ownership of regulation in the Western Region's Regulation Market was highly concentrated. There was a single pivotal supplier in 78% of the hours.

During Phases 4 and 5a in 2005, the Mid-Atlantic Region's Regulation Market became more concentrated, with higher HHIs and more frequent pivotal supply. The Western Region, by contrast, became less concentrated, with lower HHIs and less frequent pivotal supply.

Regardless of these short-term trends, the regulation market in the Mid-Atlantic Region is moderately concentrated while those in the Western Region are highly concentrated. These concentration levels are sufficiently high to lead PJM to conclude that its separate Regulation

[74] PJM 2004 SOM Report, Tables 5-2, 5-4, and 5-6, pp. 183-186.

[75] PJM 2005 SOM Report, p. 42 and Tables 6-4 and 6-8, pp. 261-263. Statistics are for "eligible" capacity.

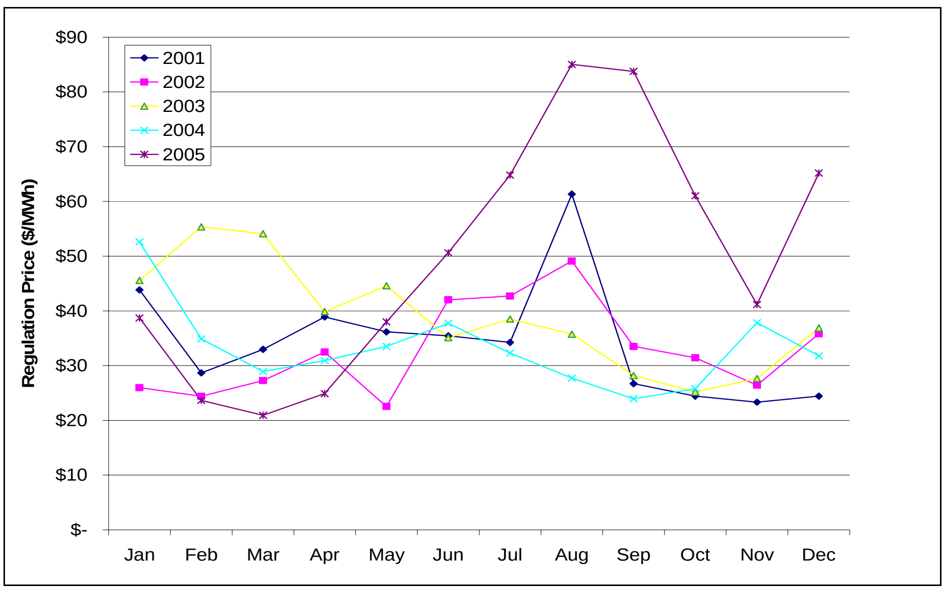
Markets are not structurally competitive.[76] The Combined Regulation Market of Phase 5b, by contrast, has lower levels of concentration and less frequent pivotal supply.

2.1.2.3. Market Performance

Figure 9 shows the monthly average regulation prices from 2001 to 2005. Regulation prices appear to follow the same general trend followed by energy prices, with a significant rise in prices in 2005 driven by the rise in natural gas prices. Figure 10 shows hourly regulation prices during 2005, indicating their high variability from one hour to the next.

In recent years, PJM's Regulation Markets have had competitive results; but this has occurred largely because PJM has capped the bids of the largest participants.[77] Because of the caps, prices have reasonably reflected the market's marginal cost of supply; and the supply offered has generally been 50% to 100% greater than the required quantity of regulation service.[78] The creation of a single Combined Regulation Market appears to be a step forward in improving the competitiveness of this market.

Figure 9
PJM Monthly Regulation Prices 2001 to 2005[79]



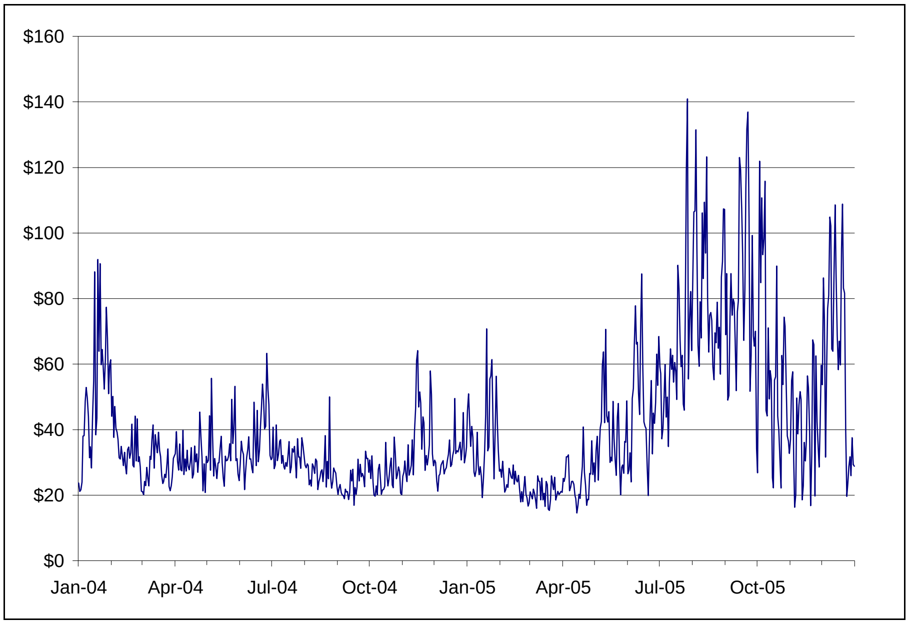
[76] PJM 2004 SOM Report, pp. 34-35 and PJM 2005 SOM Report, p. 41.

[77] PJM 2005 SOM Report, p. 23 and p. 40.

[78] PJM 2005 SOM Report, pp. 41-42.

[79] Derived from PJM regulation price data obtained from PJM website.

Figure 10
PJM Eastern Division Regulation Price, 2004 – 2005[80]



2.1.3. Reserve Markets

Order No. 888 requires that transmission providers offer "Operating Reserve – Spinning Reserve Service" and "Operating Reserve – Supplemental Reserve Service." For brevity, we refer to these as "Spinning Reserve Service" and "Supplemental Reserve Service." Order No. 888 also recognizes that transmission providers may provide Backup Reserve Service, but does not require them to do so. These services respond to longer-term deviations between system load and generation than are addressed by regulation service. Spinning Reserves respond to imbalances within a few minutes, and maintain their responses for at least thirty or sixty minutes. Supplemental Reserves respond in about ten minutes to more sustained imbalances, and also maintain their responses for at least thirty or sixty minutes. Backup Reserves become available within thirty or sixty minutes, and maintain their responses for periods of hours. PJM's Spinning Reserves are priced through market mechanisms, while its Supplemental Reserves are priced on a cost basis.

This section describes the design and structure of PJM's reserve markets, with a focus on spinning reserves.

2.1.3.1. Market Design

PJM's spinning reserve market is divided into regions, which have changed over time as PJM has expanded. The original PJM footprint, prior to when Allegheny Power (AP) joined PJM, is the Mid-Atlantic Region. When Allegheny Power joined, the spinning reserve market had two regions: the Mid-Atlantic Region and the Western Region, which included solely the AP

[80] Derived from PJM data obtained from PJM website.

Control Zone. This regional definition persisted through Phase 1 of the PJM expansion. In Phase 2, a third spinning reserve region was added for the ComEd Control Area. In Phases 3 and 4, PJM again had three spinning reserve regions: the original Mid-Atlantic Region; a Western Region comprised of the AP, AEP, and DAY Control Zones; and the ComEd Control Zone. During Phase 5, a fourth Spinning Reserve Market was created for the Dominion Control Zone.

Spinning Reserve Markets are cleared on a real-time basis. In each hour, the market-clearing price applies to all suppliers within each regional market. Spinning reserve prices are determined by supply and by PJM-defined demand. As with Regulation Service, cost-based spinning offers equal the unit-specific incremental cost of providing spinning reserve plus the opportunity cost calculated by PJM plus a margin of $7.50 per MWh.

2.1.3.2. Market Structure

Table 11 shows that PJM's spinning reserve markets are highly concentrated in all regions. Furthermore, PJM has recognized that "The structural issue can be more severe when the Spinning Reserve Market becomes local because of transmission constraints."[81] PJM also recognizes that the concentration of its spinning reserve markets may not be getting better over time.

> "While in 2003 the top 10 [spinning reserve] units were owned by four companies, in 2004 the top 10 were owned by three companies. While in 2003 the top generator represented 26.5 percent of the total operating reserves paid, in 2004 the top generator represented 20.4 percent of the total operating reserves."[82]

Table 11[83]
PJM Spinning Reserve Market HHIs

Region	Year	Phase	HHI
Mid-Atlantic	2004	3	3,100
	2005	4-5	2,940
ComEd	2004	3	8,181
	2005	4-5	8,844
Western	2004	3	5,648
	2005	4-5	4,593
Dominion	2005	5	10,000

Figure 11 shows quarterly information, by region, for 2005. The story is, again, one of high concentration in all of PJM's regions.

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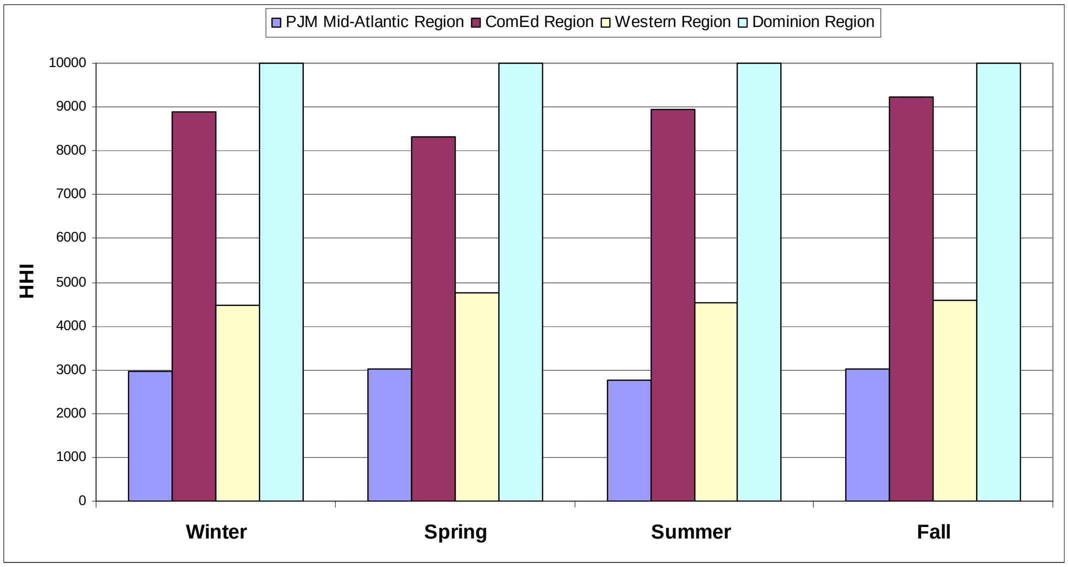
[81] PJM 2004 SOM Report, p. 193.

[82] PJM 2004 SOM Report, p. 97.

[83] PJM 2004 SOM Report, p. 36 and PJM 2005 SOM Report, p. 43.

Figure 11
HHIs for PJM's Eligible Spinning Reserves in 2005[84]



Consequently, spinning reserve prices are set according to cost-based bids rather than market based bids.

> "…the Spinning Reserve Markets in the PJM Mid-Atlantic Region and in the ComEd spinning zone were cleared based on cost-based offers because these markets were determined to be not structurally competitive."[85]

2.1.3.3. Market Performance

Table 12 summarizes Spinning Reserve prices in PJM for 2003 through 2005. On a system-wide basis, the average price associated with meeting the PJM system demand for spinning reserve has been falling slightly but steadily over time. It appears that each of PJM's regions has tended to show corresponding price declines.

Because of the high concentration of PJM's Spinning Reserve Markets, the offered supply has averaged a rather narrow 20% over requirements in the Mid-Atlantic Region and ComEd Control Zone, while averaging a more robust 75% in the Western and Southern Regions.[86] It nonetheless appears that this market has had prices that approximate competitive levels. This result is due, in large part, to the fact that some major suppliers are required to offer reserves to the market at cost-based prices.[87]

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[84] PJM 2005 SOM Report, Figure 6-15, p. 282.

[85] PJM 2004 SOM Report, p. 35.

[86] PJM 2005 SOM Report, p. 43.

[87] PJM 2005 SOM Report, p. 41.

Table 12
PJM Spinning Reserve Prices
2003 – 2005 ($/MW/hour)[88]

Year	System wide	ComEd	Dominion	Mid-Atlantic	Western
2003	15.52				26.28
2004	14.86	17.21			12.24
2005	14.41	12.73	13.08	15.44	13.23

2.1.4. Capacity Markets

This section describes the design and structure of PJM's capacity markets. It looks at the concentration in the capacity markets through the HHI and RSI statistics and presents capacity market prices.

2.1.4.1. Market Design

PJM requires that all load-serving entities in PJM maintain contracted or owned capacity equal to their load, plus a specified reserve (15% of forecasted peak in 2004, 2005, and the 2006 planning periods). They may purchase capacity bilaterally, own the capacity, or transact through the PJM capacity market.

In 2004, PJM's capacity market had two regions: northern Illinois (ComEd); and the rest of the PJM system. Therefore, capacity was initially procured through two separate processes in these two regions, with different rules and capacity requirements applicable to each region. However, a single PJM-wide process took effect June 1, 2005, when differences between PJM capacity requirements and MAIN capacity requirements were reconciled. Capacity in the northern Illinois region is measured by installed capacity (ICAP), while capacity in the rest of the system is measured by unforced capacity (UCAP), which is each generator's demonstrated capacity adjusted for its own forced outage history.

The PJM capacity markets have monthly and multi-monthly auctions, as well as a daily auction. Capacity can be purchased in any of these auctions, with monthly and multi-monthly auctions occurring at frequent intervals through PJM's website. Load-serving entities that do not procure enough resources to meet their capacity obligations must pay a deficiency payment to PJM.

2.1.4.2. Market Structure

The PJM 2004 SOM Report presents HHIs and RSI statistics for the daily, monthly, and multi-monthly capacity markets, for the latter phases of 2004 and 2005. These statistics are summarized in Tables 13 and 14.

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[88] PJM 2004 SOM Report, p. 36, and PJM 2005 SOM Report, p. 43. The Western Region figures are for AP in 2003 and AP-AEP-DAY in Phase 3 of 2004. The figure for AP in Phases 1 and 2 of 2004 was $33.37. The ComEd figure for 2004 is for Phases 2 and 3. The Dominion Figure for 2005 is for Phase 5.

Table 13[89]
PJM Capacity Market Concentration Indexes
HHIs

Period	Market	Minimum	Average	Maximum
2004 (Phase 3)	Daily	1,292	1,631	2,561
	Monthly and Multi-Monthly	1,316	2,608	4,151
2005 (Phase 5)	Daily	674	1,093	1,756
	Monthly and Multi-Monthly	1,063	2,053	5,039

Table 14[90]
PJM Capacity Market Residual Supplier Indexes
RSIs

Period	Market	Minimum	Average	Maximum
2004 (Phase 3)	Daily	2.11	6.22	9.97
	Monthly and Multi-Monthly	0.26	2.95	14.92
2005 (Phase 5)	Daily	1.56	3.27	6.19
	Monthly and Multi-Monthly	0.16	0.68	3.13

PJM's capacity markets are highly concentrated. In the fourth quarter of 2004, HHIs for the daily market averaged 1,631, with a maximum of 2,561 and a minimum of 1,292. HHIs for the monthly and multi-monthly markets were higher than the daily market. The ComEd capacity market was even more concentrated because "[o]ne entity owned or controlled nearly two-thirds of total capacity in the ComEd Control Zone."[91]

Consequently, PJM's Market Monitoring Unit (MMU) draws unfavorable conclusions about the prospects for competition in the capacity markets as presently structured.

> "Market power in the Capacity Markets remains a serious concern given the structural issues of high levels of supplier concentration, frequent occurrences of pivotal suppliers and extreme inelasticity of demand. Market power remains endemic to the structure of PJM Capacity Markets."[92]
>
> "Given the basic features of market structure in both the PJM and ComEd Capacity Markets, including high levels of concentration, the relatively small number of nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that

[89] PJM 2004 SOM Report, Table 4-1, p. 147 and PJM 2005 SOM Report, Table 5-1, p. 212.

[90] PJM 2004 SOM Report, Table 4-2, p. 147 and PJM 2005 SOM Report, Table 5-3, p. 213.

[91] PJM 2004 SOM Report, p. 170.

[92] PJM 2005 SOM Report, p. 23.

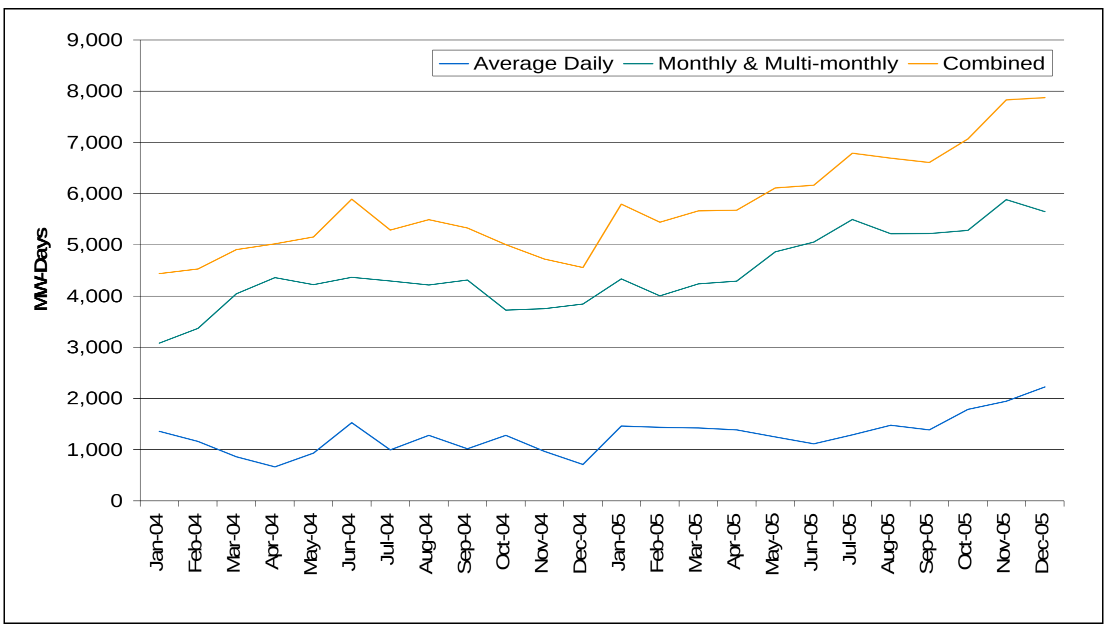
the potential for the exercise of market power is high. Market power is endemic to the existing structure of PJM Capacity Markets."[93]

2.1.4.3. *Market Performance*

Capacity prices are highest in the summer months. In the northern Illinois region, a change in seasonal obligations on October 1, 2004, caused a significant drop in auction volumes. In the rest of the system, UCAP supply fell by 1,400 MW in 2004 because of a drop in capacity imports, adjustments to forced outage rates, and generator retirements. Furthermore, the PJM market monitor noted a change in capacity bidding patterns: supply offers were higher than in previous months; and load purchased more capacity in the daily auction.

Figure 12 presents the PJM capacity market volumes for 2004 and 2005 for daily, monthly, and multi-monthly auctions. Figure 13 presents corresponding price information. Trading volumes climbed steadily over the two-year period, were fairly steady from month to month, and peaked in the summer. Prices reached a very sharp peak in the early summer of 2004, and dropped dramatically from 2004 to 2005. Summer prices are far higher than non-summer prices.

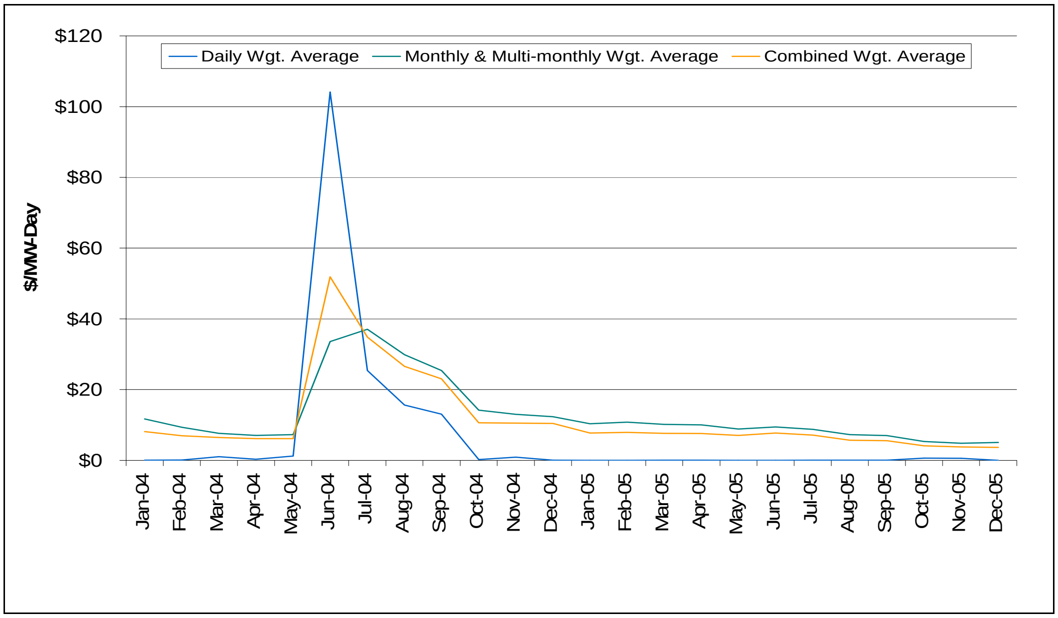
Figure 12[94]
Capacity Market Volumes, 2004 – 2005



[93] PJM 2005 SOM Report, p. 39.

[94] PJM 2004 SOM Report, Table 4-7, p. 161.

Figure 13[95]
Capacity Credit Market Prices, 2004 – 2005



Because of the excess capacity situation in 2004 and 2005, the MMU concludes that the Capacity Markets had competitive results in these years.[96]

2.1.5. Generator Operating Performance

Trends in "market heat rates" can be used as an indirect measure of improvements in average generator efficiency. The market heat rate is defined as the on-peak spot market price divided by the spot market natural gas price. This measure is intended to provide some indication of the relative efficiency of the generating units that are on the margin (and that therefore set the market-clearing price) during the peak period hours.

Figure 14 shows the "market heat rates" for PJM (based on the Western Hub on-peak spot price series) and adjacent markets. The PJM series suggests that the efficiency of the generating units at the margin has changed markedly over time but without a noticeable trend over the past five years. The PJM average over these five years has been roughly 9 MMBtu per MWh, about equal to that of a relatively efficient combustion turbine unit.

Figure 14 also shows that "market heat rates" have been consistently higher in PJM than in neighboring regions to the south and west. This reflects the fact that PJM tends to have natural gas on the margin more frequently than the neighboring regions, while the neighboring regions tend to have coal or nuclear on the margin more frequently than PJM.

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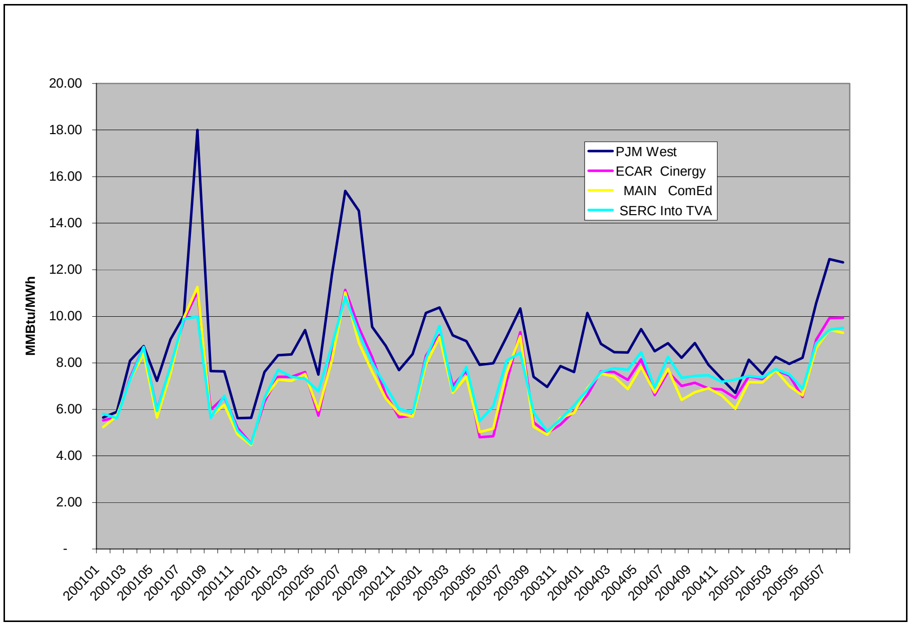
[95] PJM 2005 SOM Report, Table 5-12, p. 230.

[96] PJM 2004 SOM Report, p. 167; and PJM 2005 SOM Report, p. 23 and p. 39.

Figure 14
Market Heat Rate for PJM and Adjacent Markets, 2001 – 2005



2.1.6. Generator Conduct

Misconduct occurs whenever a supplier can be found to profitably withhold supply from the market or to profitably manipulate congestion prices. For withholding, the relevant test is whether the supplier provided all available services with marginal cost less than the market-clearing price. For manipulating congestion prices, the relevant test is whether the supplier profitably increased the value of the FTRs or generation supply that it owns.

In a competitive market, generators bid close to their marginal costs, and market prices approximate the marginal costs of the marginal generator. However, bids and market-clearing prices may differ significantly from marginal costs if there are problems with market design, if the market is not competitive, or under scarcity conditions.

2.1.6.1. Price-Cost Markups

Overall, the PJM MMU finds that, "despite concerns about market structure, the PJM Day-Ahead and Real-Time Energy Market results were competitive in 2004."[97] In particular, "data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2004."[98] PJM notes these results have occurred in spite of market structure problems because of "a combination of high levels of supply, moderate demand, and

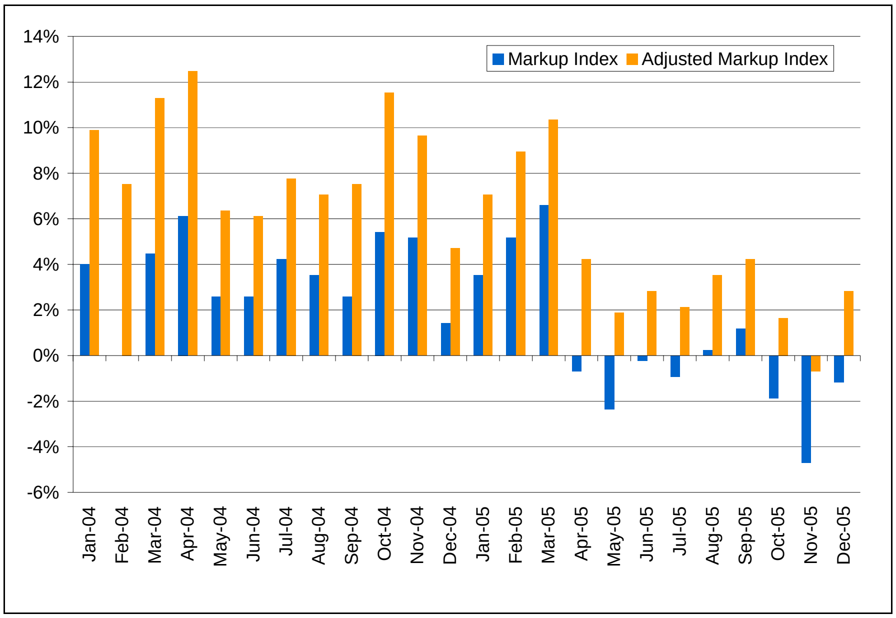
[97] PJM 2004 SOM Report, p. 45.

[98] PJM 2004 SOM Report, p. 47.

competitive participant behavior."[99] The MMU reached essentially identical conclusions for 2005.

Figure 15 presents PJM's estimated price-cost markup indices (MUIs) for 2004 and 2005. The MUI is defined as the difference between price (*P*) and marginal cost (*MC*), divided by price, where price is determined by the offer of the marginal unit and marginal cost is from the highest marginal cost unit operating, which may not be the same as the marginal unit. The markup index can be written as $MUI = (P - MC)/P$. The marginal unit is the unit that sets LMP in the five-minute interval. During congested intervals, there exist multiple marginal units; so the markup for each of the marginal units is based on that marginal unit's offer and its marginal cost during these intervals. The markup of each marginal unit is load-weighted. The MUI for each congested interval is constructed as the load-weighted average of the markups for each of the marginal units.

Figure 15
Average Monthly Load-Weighted Price-Cost Markup Indices, 2004 and 2005[100]



The markup index can vary from plus 1.00 when the offer price is substantially higher than marginal cost, to negative values when a marginal unit offers its output at less than marginal cost. This latter situation is not implausible because units in PJM may provide a cost curve equal to cost plus 10%. Thus the index can be negative if the marginal unit's offer price is between cost and cost plus 10%.

The price-cost markup index for 2004 and 2005 indicates that the energy supply bids that set the market-clearing prices were offered at prices averaging about 3.4% and 0.3% above marginal cost, respectively.[101] Because the foregoing measure of "marginal cost" may actually be up to

[99] PJM 2004 SOM Report, p. 21.

[100] PJM 2004 SOM Report, Figure 2-6, p. 68, and PJM 2005 SOM Report, Figure 2-8, p. 83.

[101] PJM 2004 SOM Report, p. 68 and PJM 2005 SOM Report, p. 84.

10% above true marginal cost, Figure 15 also presents an adjusted markup index that assumes that all suppliers have overstated marginal costs by 10%. The adjusted markup index provides a plausible upper bound on how high the true price-cost markup might be.

Figure 16 presents the average annual markup index by fuel type for the years 2000 through 2005. The largest markups in 2005 are for oil-fired units, with average markups of about 10%. While oil-fired units have been on the margin setting the market-clearing price in the past in PJM, they have been displaced recently by gas-fired units and coal-fired units. In 2000, oil-fired units were on the margin 31% of the hours whereas in 2004 they were on the margin only 12% of the hours. In contrast, coal and gas-fired units were on the margin 48% and 18% respectively in 2000, rising to 62% and 26% of the time by 2005.[102] The markup index for coal-fired units is negative for 2005 because offer prices tended to be below marginal cost or between marginal cost and marginal cost plus 10% (PJM permits all units to be offered at marginal cost plus 10%). The markup index can be negative when unit offer prices are below marginal cost. This can happen for baseload coal units that are offered at prices that ensure those units will be dispatched.

Figure 16
Average Price-Cost Markup Index by Fuel Type, 2000 – 2005[103]

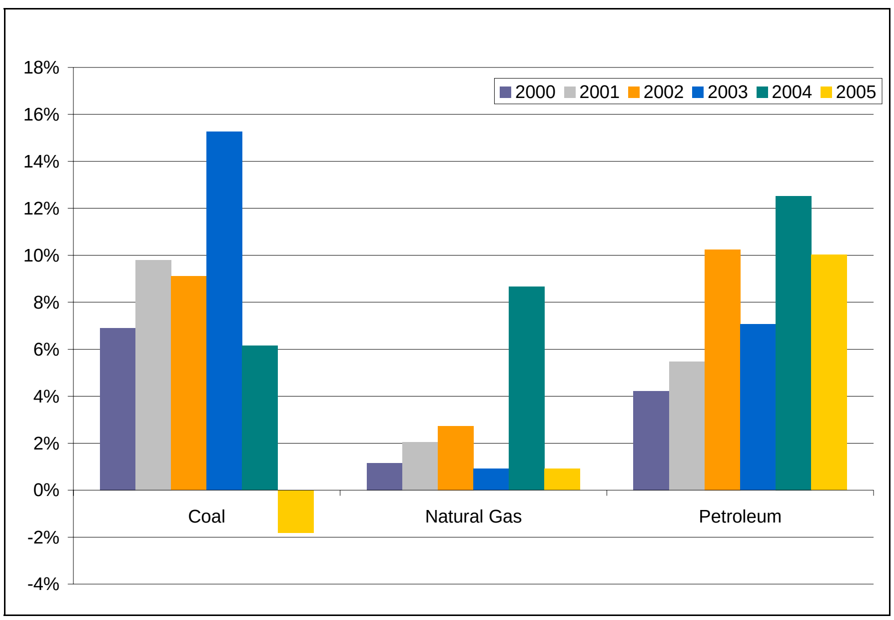


Table 15 shows the type of unit that was setting the market-clearing price over the period from 2000 to 2005. The pattern shows a shift away from combustion turbines to steam units over this time period. Combustion turbines were on the margin 37% of the hours in 2000 but only 23% of the hours in 2005, whereas steam units on the margin rose from 63% in 2000 to 77% in 2005.

[102] PJM 2005 SOM Report, p. 86.

[103] PJM 2004 SOM Report, Figure 2-7, p. 69, and PJM 2005 SOM Report, Figure 2-10, p. 85.

Table 15
Type of Unit on the Margin in PJM: 2000 to 2005[104]

Unit Type	2000	2001	2002	2003	2004	2005
Combustion Turbine	37%	33%	26%	22%	22%	23%
Steam	63%	67%	74%	77%	77%	77%

2.1.6.2. Generator Availability Rates

The introduction of competitive wholesale electricity markets has provided incentives for improved generator performance. Such improved performance would partly be reflected in higher generation availability rates, which are basically defined as the percentage of time during which generators are not on maintenance, planned outage, or forced outage.

Figure 17 shows PJM's average generator availability rate for the period 1994 through 2005. The availability factor, represented by the solid line, equals 100% minus the maintenance outage factor, planned outage factor, and forced outage factor. The figure shows that availability rose appreciably from 1994 through 1998, before PJM became an ISO. Since that time, the availability rate has held fairly steady in the 85% to 87% range.

Figure 17
Trends in PJM's Generator Availability and Outage Rates, 1994 – 2005[105]

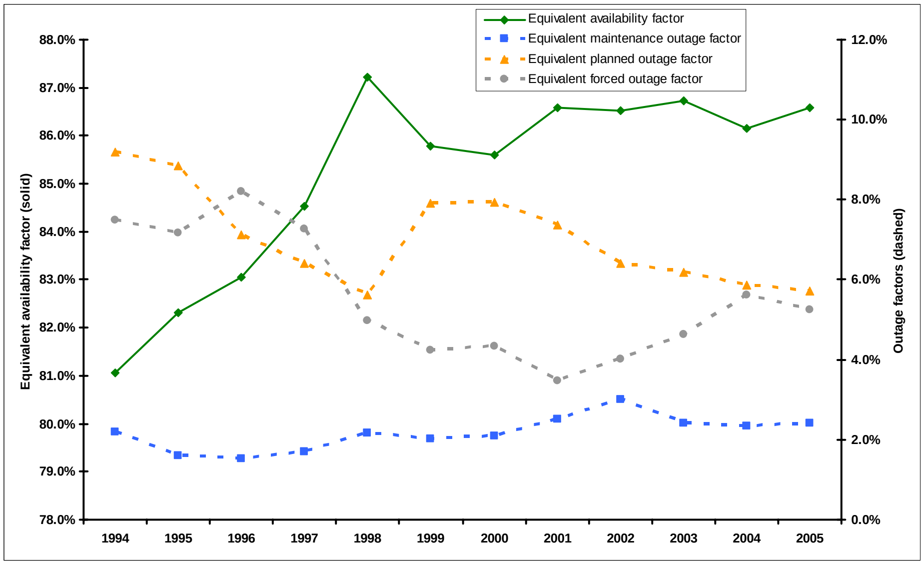


Table 16 looks at the history of PJM's generator outages over the past five years. Overall, PJM's forced outage rates seem to be trending upward. PJM's nuclear performance has nonetheless been consistently better than the national average. On the other hand, steam units—which provide the majority of PJM's electrical energy—have had outage rates that are higher than the national average.

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[104] PJM 2004 SOM Report, Table 2-26, P. 71 and PJM 2005 SOM Report, Table 2-19, p. 87.

[105] PJM 2005 SOM Report, Figure 5-10, p. 243.

Table 16
Equivalent Forced Outage Rates for PJM vs. NERC, 2001 to 2005[106]

	PJM					NERC
Unit Type	**2001**	**2002**	**2003**	**2004**	**2005**	**2000-2004**
Combined Cycle	1.7%	5.3%	5.7%	6.5%	5.3%	NA
Combustion Turbine	4.6%	4.4%	8.9%	9.3%	14.0%	8.9/10.1%
Diesel	10.6%	7.1%	5.7%	10.4%	14.0%	14.1%
Run of River Hydro	1.2%	1.0%	0.9%	2.5%	1.9%	3.6%
Nuclear	1.5%	1.7%	2.1%	3.4%	1.4%	4.3%
Pumped Storage	0.6%	1.1%	1.3%	2.1%	1.2%	4.6%
Steam	6.4%	7.1%	9.0%	10.3%	8.6%	6.2%
Overall	4.6%	5.2%	7.0%	8.0%	7.3%	NA

2.2. Midwest ISO

The Midwest ISO has a footprint that covers 947,000 square miles in all or parts of 15 states, plus the Canadian province of Manitoba. The footprint has 98,600 miles high-voltage transmission lines, 170,000 MW of installed capacity, and 131,400 MW of peak demand. Because the Midwest ISO's markets do not encompass the entire footprint, the markets have 140,000 MW of installed capacity and 112,200 MW of peak demand. The ISO has 590 employees.[107]

Table 17 summarizes the Midwest ISO's membership at the end of 2005.

Table 17
Midwest ISO Membership, 2005[108]

Transmission Owning Members:	
coordination company	1
vertically integrated utilities	17
municipalities and cooperatives	9
stand-alone transmission companies	3
Subtotal – Transmission Owners	32
Non-Transmission Owning Members	60
Total	92

This section begins with discussions of the energy market, and then discusses how Midwest ISO handles ancillary services and resource adequacy. We then consider generator operating performance and generator conduct.

[106] PJM 2005 SOM Report, Table 5-25, p. 246.

[107] Midwest ISO 2005 Annual Report, p. 10.

[108] Midwest ISO 2005 Annual Report, p. 11.

2.2.1. Energy Markets

2.2.1.1. Market Design

Prior to the introduction of the Day 2 Market in April 2005, the energy market was limited to bilateral trading.[109] The Day 2 Market allows a continuation of bilateral trading but additionally offers centralized Day-Ahead and Real-Time Energy Markets.

Energy trades occur at each of approximately 1,500 Commercial Pricing Nodes, which are groupings of one or more generation and/or load elemental nodes. Thus, load scheduling, generation scheduling, and metering all occur at the Commercial Pricing Nodes.[110] In addition, there are four financial trading hubs: Minnesota, Cinergy, Michigan, and Illinois, the latter of which was created in February 2005. These trading hubs can help simplify market participants' hedging of their energy positions.[111]

In the Day-Ahead Energy Market, market participants can make the following types of bids to buy or sell power:[112]

- *Fixed demand bids* specify purchase quantities that do not depend upon price. In this case, the buyer pays whatever the market price turns out to be.
- *Price-sensitive demand bids* specify purchase quantities that depend upon price. In general, the bid quantity will go down as price goes up.
- *Virtual demand bids* are purchase bids that may be speculative in that they are not intended to serve physical load, but are instead intended to profit from energy prices that are higher in the Real-Time Market than in the Day-Ahead Market.
- *Generation offers* specifies sales quantities and prices, where sales are from physical resources. The offer can be a multi-part bid consisting of Start-up, No-Load and Incremental Cost components. Generation offers can be made in the Real-Time Market just as in the Day-Ahead Market.
- *Virtual supply offers* are sales offers that may be speculative in that they are not intended to be supplied by physical resources, but are instead intended to profit from energy prices that are lower in the Real-Time Market than in the Day-Ahead Market.

Virtual transactions that are cleared in the Day-Ahead market are automatically reversed in the Real-Time market; so "Cleared virtual transactions do not cause any physical flow…"[113] Instead, virtual transactions have only financial effects. First, these transactions impact Day-

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[109] Midwest ISO 2004 SOM Report, p. iv.

[110] DMAR 2/1/06, p. 5.

[111] The LMPs computed for the commercial pricing nodes include computation of a marginal loss component in contrast to PJM's approach which assesses transmission users for line losses on the basis of average loss factors. Marginal losses are roughly double average losses. To adjust for this fact, the Midwest ISO returns to LSEs the difference between average loss factors and payments made based on marginal losses.

[112] DMAR 2/1/06, p. 5.

[113] Midwest ISO, *Frequently Asked Questions – Virtual Transactions*, p. 3.

Ahead LMPs. Second, the parties who undertake these transaction gain or lose monies equal to the volumes of their transactions times the difference the Day-Ahead and Real-Time LMPs at their transaction locations.

2.2.1.2. Market Structure

The Midwest ISO footprint has over 150 distinct owners of generation.[114] The result, as indicated in Table 18, is that, over the whole footprint, the market would appear to be unconcentrated, with the HHI for 2004 at a very low 356. Because of transmission constraints, however, the sub-regional HHIs are more relevant; and these show that the Central sub-region is moderately concentrated, while the East, West, and WUMS sub-regions are highly concentrated. In each of the latter three sub-regions, the top three suppliers control around 75% of supply. In MAIN and MAPP, there is a pivotal supplier in 20% of all hours, while in WUMS, there is a pivotal supplier in more than 75% of all hours.[115] Consequently, "the most significant potential competitive concerns in the Midwest are in the WUMS area."[116]

Table 18
HHIs in the Midwest ISO's Sub-Regions, 2002 – 2005 [117]

Midwest ISO Subregion[118]	HHI			
	2002	2003	2004	2005
East (ECAR)	1,087	563	770	2,072
Central (MAIN)[119]	1,669	1,736	1,745	1,253
West (MAPP)[120]	1,128	938	1,275	2,397
WUMS	2,752	2,656	2,642	2,918
Midwest ISO	**408**	**261**	**356**	**548**

During 2005, "there was an active BCA [broad constrained area] constraint with at least one pivotal supplier in two-thirds of the hours and an active NCA [narrow constrained area] constraint with a pivotal supplier in almost 30 percent of the hours. Hence, substantial local market power is associated with the BCA and NCA constraints…"[121]

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[114] Midwest ISO 2004 SOM Report, p. 3.

[115] Patton, Midwest ISO 2005 SOM Presentation, p. 16; and Midwest ISO 2005 SOM, p. 10.

[116] Midwest ISO 2004 SOM Report, p. 11.

[117] Midwest ISO 2004 SOM Report, Table 3, p. 10; Patton, Midwest ISO 2005 SOM Presentation, p. 135; and Midwest ISO 2005 SOM Report, Figure 53, p. 73. Midwest ISO 2005 SOM Report, p. 10 explains the correspondence between the subregions presented for 2002-2004 and the 2005 regions.

[118] There are general but inexact correspondences between the East, Central, and West regions of 2005 and the ECAR, MAIN, and MAPP regions before 2005. See Midwest ISO 2005 SOM, p. 10.

[119] The HHIs for 2002 and 2003 exclude Commonwealth Edison. The HHI for 2003 excludes Illinois Power. All HHIs for MAIN in all years exclude the WUMS utilities.

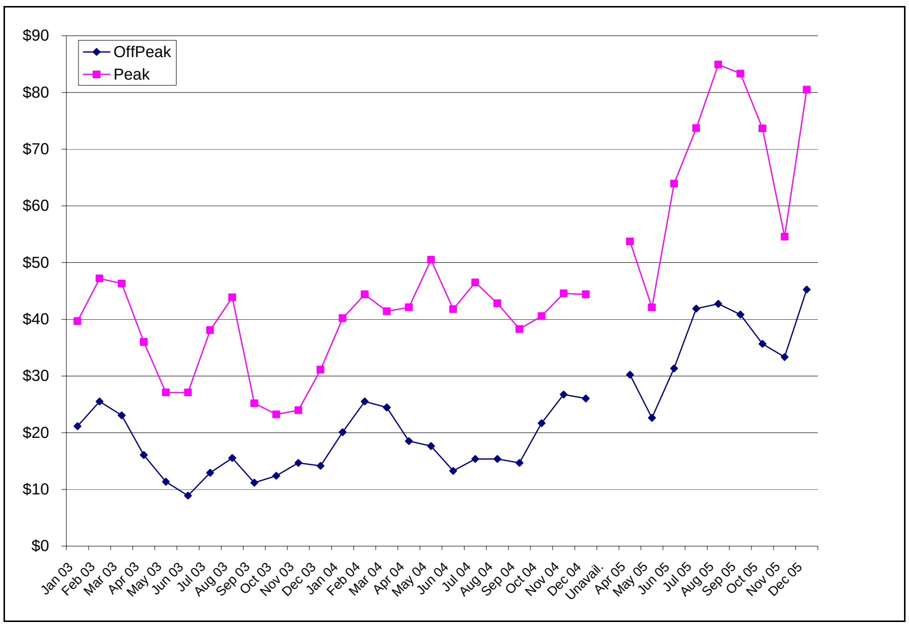
[120] The HHI for 2003 excludes Iowa.

[121] Patton, Midwest ISO 2005 SOM Presentation, p. 17.

2.2.1.3. Market Performance

Electricity prices depend upon fuel prices, especially for the fuels that are used by marginal generators. Because the generation fuel mix in the Midwest ISO is 60% coal, 20% gas, and 17% nuclear,[122] and because coal and gas are the fuels most likely to fire the marginal generators, electricity prices in the Midwest ISO have followed coal and gas prices in the generally upward and often erratic climb of the past few years. Figure 18 shows monthly average electricity prices at the Midwest ISO's major trading hub in 2003 through 2005.

Figure 18
Monthly Average Day-Ahead Electricity Prices at the Cinergy Hub, 2003 – 2005[123]



The Day-Ahead Market has been an accurate predictor of real-time conditions. Excluding the effects of the Ludington Pumped Storage facility, Day-Ahead scheduled MWs have been within 1% of Real-Time scheduled MWs. The Ludington facility, by contrast, has had a substantial impact on creating discrepancies between Day-Ahead and Real-Time Markets, raising the discrepancy all the way up to 8%.[124] The convergence of day-ahead and real-time prices is partly attributable to the active market in day-ahead virtual trades.[125] Indeed, "almost all of the price-sensitivity on the demand side in the day-ahead market is provided by the virtual traders rather than by physical loads."[126] Despite its significant benefits in promoting the efficiency of

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[122] Midwest ISO 2004 SOM Report, p. 9.

[123] 2003 and 2004 prices are from Midwest ISO 2004 SOM Report, Figure 9, p. 17. April 2005 to December 2005 prices are from Midwest ISO website. January 2005 to March 2005 prices are not available.

[124] Spence 1/31/06, p. 3.

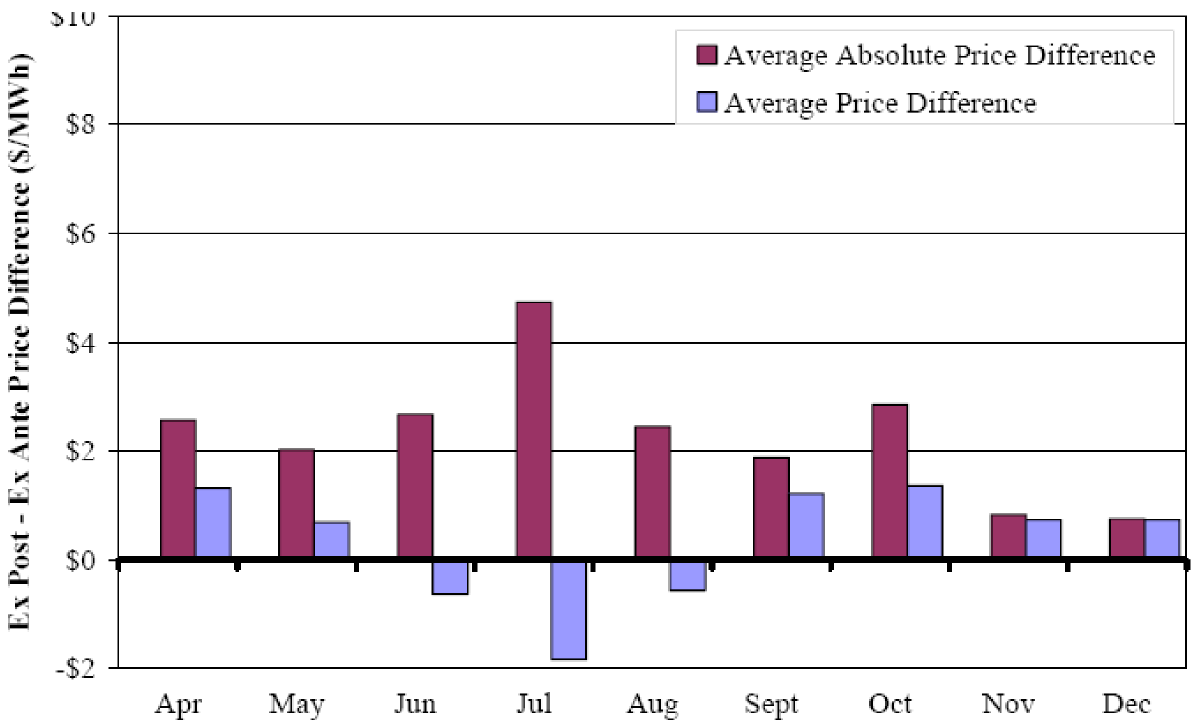
[125] Patton, Midwest ISO 2005 SOM Presentation, p. 7 and p. 61.

[126] Patton, Midwest ISO 2005 SOM, p. 32.

the Midwest ISO's energy markets, virtual trading may have been significantly damaged recently by FERC's decision to impose RSG charges on virtual transactions.[127]

Furthermore, there is a general convergence between the Midwest ISO's *ex ante* and *ex post* real-time prices. The *ex ante* prices are those that the Midwest ISO announces before the fact, and to which generators respond. The *ex post* prices are those that the Midwest ISO actually pays to generators. Ideally, the two sets of prices would be identical. Figure 19 shows that there is some difference between the two sets, averaging close to zero over all hours of 2005 though nearly $2 per MWh in July. Figure 20 shows that the largest differences occurred in the first four months of the Day 2 market, after which the Midwest ISO apparently improved in *ex post* pricing methods.

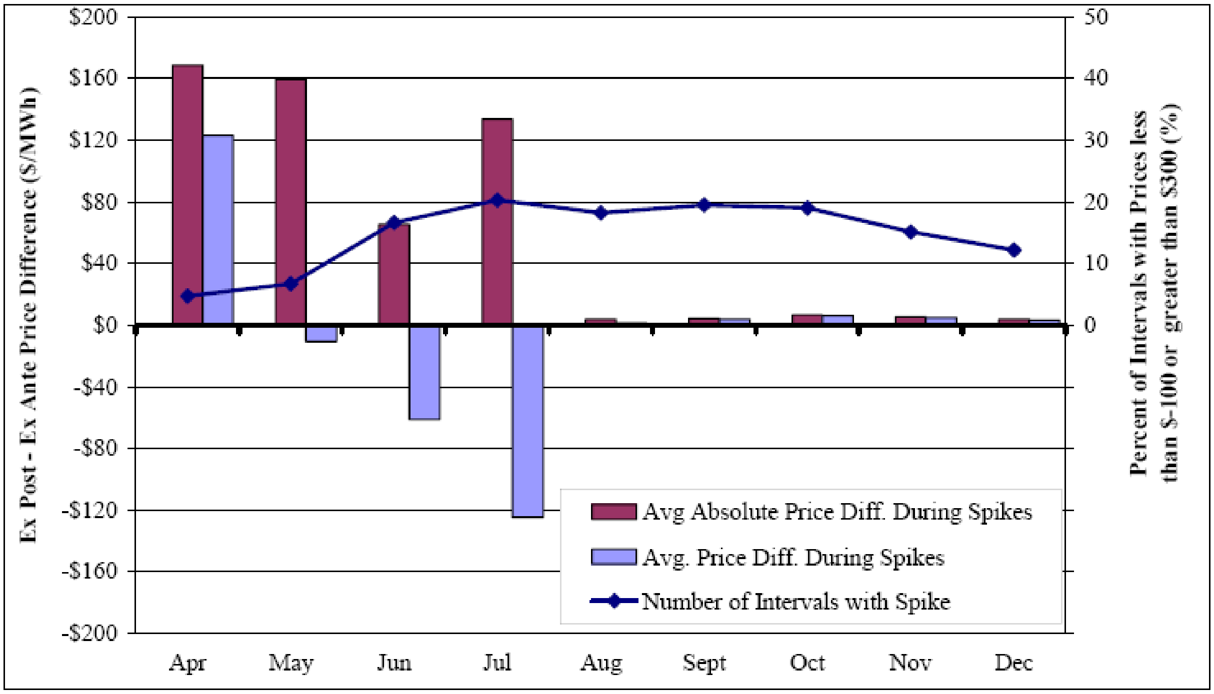
Figure 19
Monthly Average Differences Between *Ex Ante* and *Ex Post* Prices, 2005 [128]



[127] Federal Energy Regulatory Commission, *Order Requiring Refunds, and Conditionally Accepting in Part, and Rejecting in Part Tariff Sheets*, Docket No. ER04-691-065. See Sections 3.2.2 and 8.2.1.1 for further discussion of the Midwest ISO's RSG.

[128] Midwest ISO 2005 SOM, Figure 35, p. 48.

Figure 20
Differences Between *Ex Ante* and *Ex Post* Prices During Price Spikes, 2005 [129]



On the other hand, the Midwest ISO market is biased in a manner that encourages load to under-schedule in the day-ahead market. The bias is created by Midwest ISO's "supplemental commitment" of generators after the closing of the day-ahead market. With this supplemental commitment, the Midwest ISO pays generators to become available in real-time even though they were not scheduled to be available in the day-ahead market. Load-serving entities thus correctly anticipate that this administrative process will make more generation available to the real-time market than is available in the day-ahead market, so they reduce their day-ahead purchases accordingly. The actual result has been that day-ahead loads have been consistently less than real-time loads.[130] The administrative intervention in the market, coupled with LSEs rational response to that intervention, undermines the market's efficiency.[131]

Market efficiency is also reduced by the inconsistent treatment of peaking generators in the day-ahead and real-time markets. Peaking units set prices when their bids are accepted in the day-ahead market; but if their operational inflexibility makes them unresponsive to small changes in loads, they do not set prices in the real-time market.[132] In other words, real-time LMPs are sometimes set according to the bids of infra-marginal generators rather than according to those of

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[129] Midwest ISO 2005 SOM, Figure 36, p. 49.

[130] Patton, Midwest ISO 2005 SOM Presentation, p. 6.

[131] Note that the under-scheduling of load is *not* due to load forecasting errors. The IMM finds that day-ahead peak-hour load forecasts in the last nine months of 2005 differed by an average of 0.2% from actual real-time loads, with an average absolute error of 2%. Patton, Midwest ISO 2005 SOM Presentation, p. 70.

[132] Patton, Midwest ISO 2005 SOM Presentation, p. 65.

peaking generators. The IMM notes that "a large share of the peaking resources are dispatched out-of-merit (offer > LMP), indicating that they frequently do not set the energy price."[133]

Furthermore, the real-time market's performance is also compromised by generators bidding less operational flexibility than they have. According to the IMM, generators that have operating flexibility over 60% of their capacity are only offering to the market flexibility over 25% of their capacity. This unwillingness to provide all of their flexibility to the market inevitably raises the costs of generating electricity, and can also create or exacerbate transmission constraints.[134]

2.2.2. Ancillary Services

Midwest ISO presently lacks markets for ancillary services. In imitation of PJM, it proposes to create markets for regulating reserves and contingency (spinning) reserves, with simultaneous co-optimization of energy and ancillary service markets. With both energy and reserve markets, more generators would commit themselves (i.e., start up) than is the case with only energy markets. Reserve markets could thus provide market-based incentives for generator commitment.

As a partial, if unintentional, substitute for reserve markets, Midwest ISO instead has a Reliability Assessment Commitment (RAC) process under which it guarantees full cost recovery for those generators that are committed by Midwest ISO. Thus, generators that the ISO commits for reliability purposes are guaranteed recovery of their as-bid start-up costs, no-load costs, and incremental energy offer costs during the Midwest ISO-nominated Commitment Period, even if the generators do not provide energy above their minimum operation levels. Midwest ISO makes this guarantee good through Revenue Sufficiency Guarantee (RSG) payments. Those generators that commit themselves in response to energy prices do not receive RSG payments. With reserve markets, the need for RSG would be reduced and might even be eliminated.

Because of the absence of reserve markets and because energy prices are often set according to the costs of infra-marginal units rather than according to those of peaking units, RSG payments were a hefty $600 million in 2005. A significant portion of these costs were incurred to maintain reliability in load pockets. To allow peaking units to recover their costs in a market in which energy prices are often set below marginal cost, about 75% of RSG payments have gone to peaking resources that produce only 2% of Midwest ISO's energy.[135]

2.2.3. Resource Adequacy[136]

The Midwest ISO's resource adequacy requirement basically piggy-backs on the resource adequacy requirements of the states in which loads are located. Load-serving entities (LSEs) must meet these requirements according to the locations of their loads, not their resources. If a

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[133] Patton, Midwest ISO 2005 SOM Presentation, p. 10.

[134] Patton, Midwest ISO 2005 SOM Presentation, p. 8.

[135] Patton, Midwest ISO 2005 SOM Presentation, p. 9.

[136] See EMT, Sheet Nos. 810-826.

state lacks a resource requirement or has an indeterminate resource requirement, the Midwest ISO imposes an annual reserve requirement of 12% of the load located in that state.

In general, the resource adequacy requirement is based on each LSE's forecast peak hourly load for the next twelve months. LSEs can adjust their forecast up to thirty days before the beginning of each month.

LSEs must designate, in advance, the generation or demand-side resources that satisfy the resource adequacy requirement. These resources must be deliverable to load, as determined by the Midwest ISO's System Impact Studies.

It does not appear that the Midwest ISO has penalties or other mechanisms by which it forces compliance with its resource adequacy requirement.

2.2.4. Generator Operating Performance

As discussed in Section 2.1.5, generator operating performance can be examined roughly through market heat rates. The market heat rate for generation operating within the Midwest ISO footprint is represented in Figure 14 for the period 2001 to 2005, based on the prices at the ComEd hub. While the market heat rates in the Midwest ISO region are lower than for PJM, they tend to follow the same pattern as all other regions.

2.2.5. Generator Conduct

2.2.5.1. Price-Cost Markups

Neither the Midwest ISO nor its IMM has reported price-cost markups, nor have they reported the cost data necessary for an independent calculation of price-cost markups. We are therefore unable to present price-cost markup information at this time.[137]

2.2.5.2. Generator Availability Rates

Figure 21 shows monthly average generation outage rates for 2005. Over the year, these averaged about 10%, of which about 5.5% was planned and the remainder was forced (unplanned). Consistent with the fact that loads and the consequent need for capacity are highest in the winter and summer, both forced outages and total outages were highest in the spring and fall. Equivalent forced outage (EFORd) rates from 2002 to 2005 period have been fairly consistent, from a maximum of 7.11 percent in 2002 to a minimum of 6.14 percent in 2004. The EFORd rate in 2005 (about 7%) is slightly higher that the rate in 2004 (about 6.1%) and would be cause for concern if it meant that physical withholding was taking place in 2005, which according to the IMM's analysis was not the case.[138]

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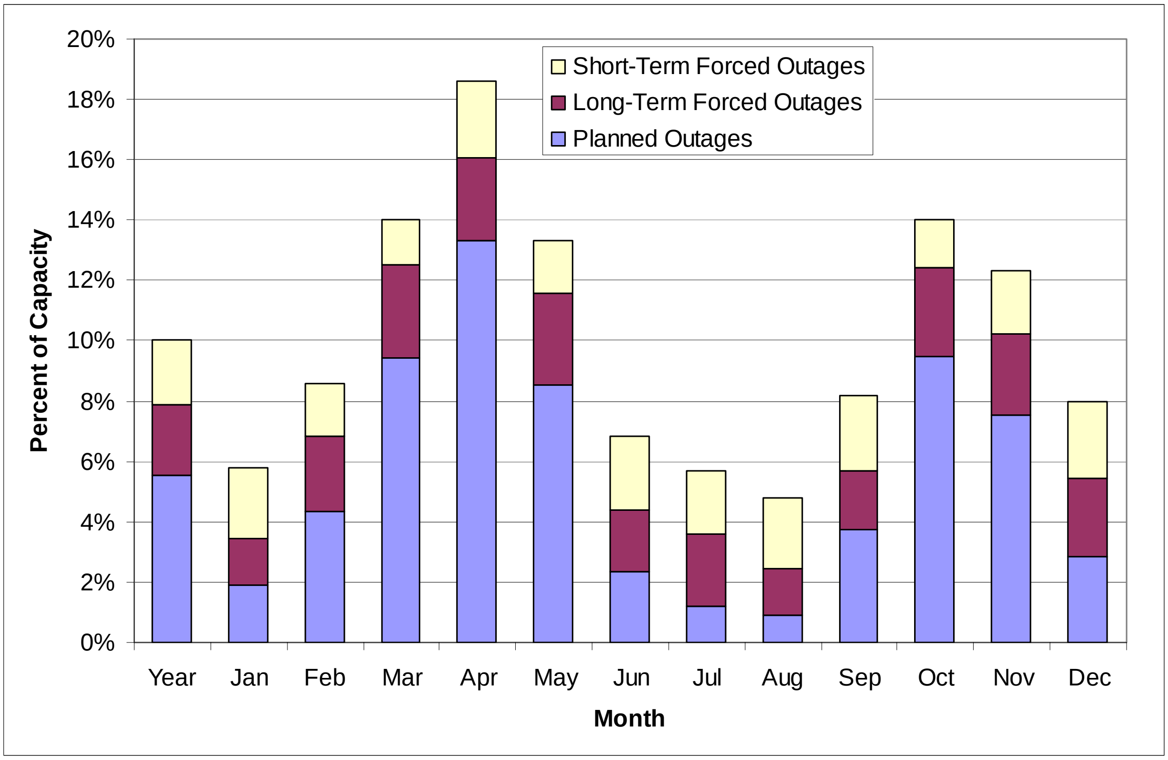
[137] We will attempt to obtain the data necessary to compute price-cost markups for the next Report Card.

[138] 2005 SOM Report, p. 19.

Figure 21
Midwest ISO's Monthly Average Generation Outage Rates, 2005 [139]



2.2.5.3. Generator Behavior

The Midwest ISO IMM attempts to measure the extent to which generators attempt to exercise market power by examining withholding supply from the market. Some withholding can be detected by comparing actual generator offer prices with competitive offer prices, which requires a competitive benchmark price to be constructed as a basis for reference.[140] Figure 22 provides such a comparison, showing the average number of MW offered by generators at prices that exceed the generators' mitigation thresholds (as determined by the Midwest ISO IMM) for each two-week period from June to December of 2005. The left side of the figure shows the average MW offered at prices that exceed the mitigation thresholds for minimum generation offers (for capacity up to the unit's minimum operating level). The right side of the figure shows the average MW offered at prices that exceed the mitigation thresholds for energy (for capacity above the unit's minimum operating level). Each chart shows the average MW that were offered at prices that exceed the thresholds by 50% and by 100%, which would be considered significant price-cost markups by any standard. The right side of the figure indicates that there were three periods in which there were more than 500 MW offered into the real-time market at average

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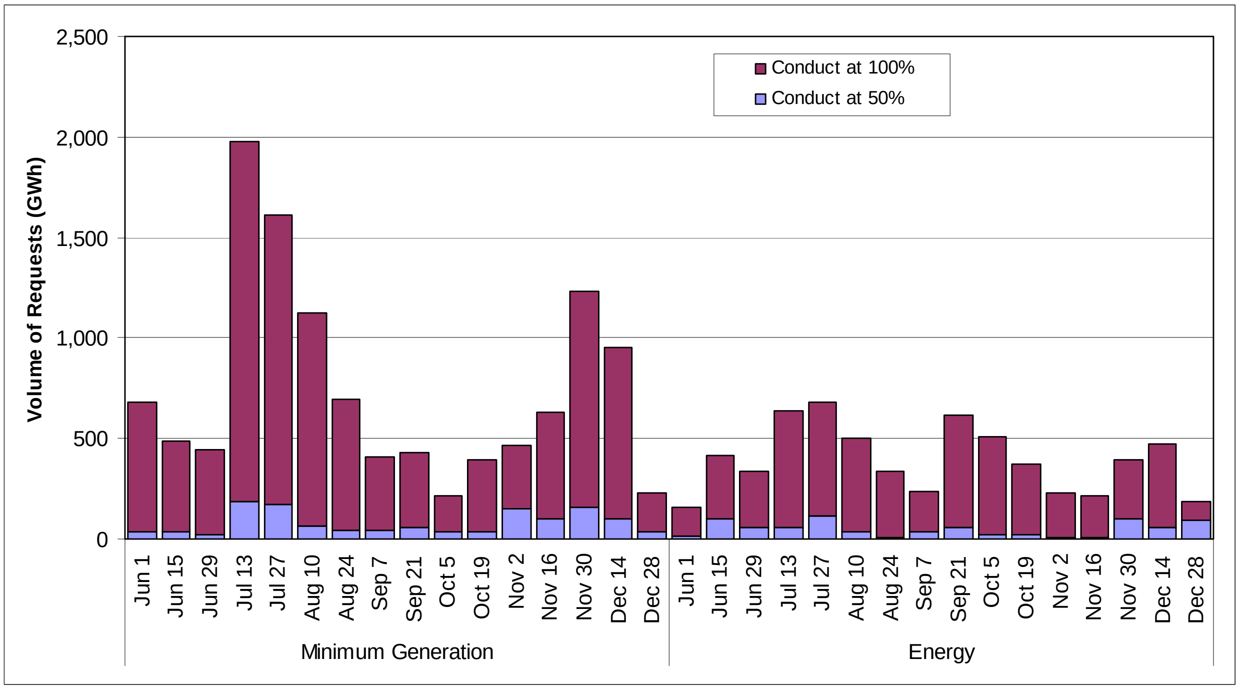
[139] 2005 SOM Report, Figure 12, p. 17.

[140] This is similar to the price-cost markup measure employed by the PJM IMM, except that the Midwest ISO IMM uses data supplied by the generators to establish reference thresholds intended to reflect each unit's marginal costs at various output levels. These reference thresholds are used by the IMM throughout the year as part of the market power monitoring and mitigation process.

prices 50% above the mitigation thresholds, and four periods in which around 100 MW were offered at average prices 100% above the thresholds. From these two charts, the IMM concludes that excess bids were low in quantity, relative to the total amount of generation capacity committed on a daily basis in Midwest ISO, and that generator behavior was therefore competitive.

Figure 22
Midwest ISO Generator Capacity Offered at Prices Above the Mitigation Thresholds in the Real-Time Market, 2005[141]



While Figure 22 may be suggestive that there was little market power exercised in the real-time energy market, given that the markup threshold represented is 50% and 100%, it is quite possible that price-cost markups that were lower but still significant enough to constitute withholding and an exercise of market power took place.

The Midwest ISO IMM also measures generator market power behavior through the "output gap." The IMM defines the metric as:

> "The output gap is the difference between the unit's output that is economic at the prevailing clearing price and the amount that is actually produced by the unit. In essence, the output gap shows the quantity of generation that is withheld from the market as a result of having submitted offers above competitive levels."[142]

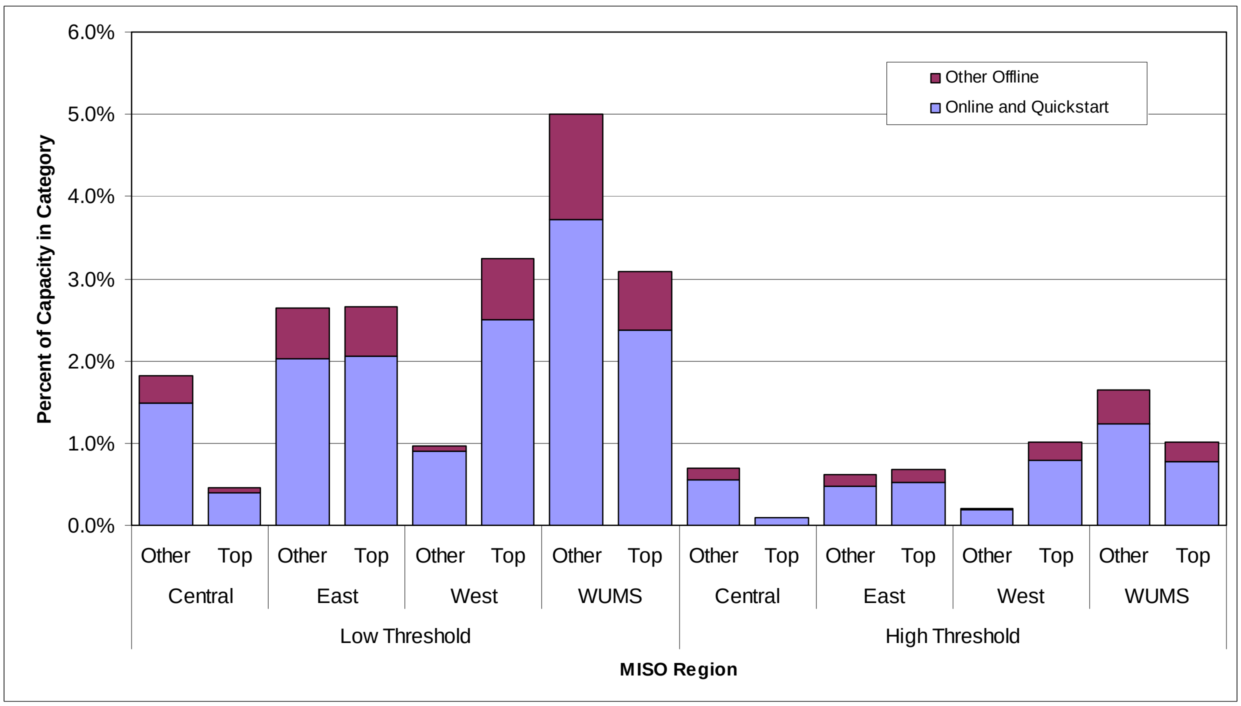
Figure 23 shows the output gap as a percentage of the total economic output for each subregion when the Midwest ISO load exceeds 100 GW. The "High Threshold" results are based upon the

[141] Midwest ISO 2005 SOM, Figure 58, p. 80.

[142] 2005 SOM Report, p. 81.

Midwest ISO's mitigation thresholds, while the "Low Threshold" results are based upon thresholds equal to half of the mitigation thresholds. Results are shown for the top two suppliers and for all other suppliers. The output gap ranges between 1% and 5% for the Low Threshold cases and are around 1% for the High Threshold cases. Interestingly, the output gap for the top two suppliers is consistently lower than for other suppliers, which contradicts the supposition that the output gap results from an exercise of market power.

Figure 23 Midwest ISO's Real-Time Market Output Gap at 100 GW+ Load, by Subregion, 2005[143]



As the IMM states: "any measure of potential withholding will inevitably include quantities that can be justified for a variety of reasons, we … evaluate not only the absolute level of the output gap, but also how it varies with factors that can create the ability and incentive for a pivotal supplier to exercise market power."[144] Thus, the IMM reports the "output gap" metric in terms of the generator capacity and total load served in the real-time market, which enables the IMM to examine how offer prices vary with certain factors that characterize periods when market power is more likely to be exercised. In particular, larger suppliers are more likely to be pivotal and generally have a greater incentive to increase prices than relatively small suppliers. Load level is important because the sensitivity of prices to withholding generally increases as the load increases. This is due, in part, to the fact that rivals' resources will be more fully utilized serving load under these conditions, leaving only high-cost resources (or no resources in the case of a pivotal supplier) that can respond to the withholding.[145]

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[143] Midwest ISO 2005 SOM, Figures 59 through 62.

[144] *Ibid*.

[145] 2005 SOM Report, p. 83.

The IMM concludes on the basis of the output gap analysis that "[o]verall, these results indicate that the participants engaged in *very little economic withholding* and, thus, the results do not raise substantial competitive concerns."[146] Apparently, some economic withholding took place in the Midwest ISO energy markets in 2005, which presumably raised market prices above competitive levels; but the impact of this withholding was not large enough to induce the IMM to mitigate generator behavior.

The IMM also examines forced outages and deratings of generators for evidence of physical withholding. He finds that "deratings and outages do not rise significantly under peak load conditions" and that deratings of "the largest suppliers are generally lower than for other suppliers."[147] This evidence leads the IMM to conclude that "physical withholding was not a concern in 2005."[148] The evidence presented on economic withholding and physical withholding would suggest that if generators in the Midwest ISO territory are attempting to exercise market power, they are more likely to be doing it through economic withholding rather than through physical withholding.

Overall, the IMM finds that "in 2005… There was very little evidence of any exercises of market power…"[149] Consequently, "mitigation was infrequent because participants did not engage in significant economic or physical withholding, even when they had substantial local market power."[150] "Energy offers were mitigated for BCA constraints in 24 instances and for NCA constraints in 62 instances. This mitigation occurs pursuant to automated conduct and impact tests…"[151] All told, in the eight months of the Day 2 Market in 2005, a mere 10,000 MWh of energy output was price-mitigated.[152]

Although the IMM found little evidence of suppliers *exercising* market power, the IMM does find that suppliers *have* market power. When the supply surplus ends, suppliers may be more inclined to exercise the market power that they have. Furthermore, the IMM is rightly concerned that FERC has recently curtailed the IMM's enforcement powers:

> "[L]ocal market power… exists across the entire Midwest ISO region based on our studies. However, the market power mitigation to address local market power outside of the WUMS (i.e., in "Broad Constrained Areas" or BCAs) has expired, leaving the market vulnerable to substantial market power abuses."[153]

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[146] 2005 SOM Report, p. 85, emphasis added.

[147] Midwest ISO 2005 SOM, p. 88.

[148] 2005 SOM Report, p. 89.

[149] Patton, Midwest ISO 2005 SOM Presentation, p. 3.

[150] Midwest ISO 2005 SOM, p. 90.

[151] Patton, Midwest ISO 2005 SOM Presentation, p. 17.

[152] Midwest ISO 2005 SOM, Figure 67, p. 90.

[153] Patton, Midwest ISO 2005 SOM Presentation, p. 138.

2.3. Third RTO

2.4. Summary and Implications

For wholesale markets in all regions of the U.S., electricity prices have risen in 2005 over 2004. The dramatic rise in fuel prices, especially those of natural gas, has been one of the primary drivers.

In PJM, hourly real-time prices in 2004 generally ranged between $10 and $70 per MWh, while in 2005 they generally ranged between $20 and $110. This rise in market prices primarily reflects increases in fossil fuel (i.e., gas and coal) prices and the impact of the market clearing price mechanism. Nonetheless, the percentage rise in wholesale electricity prices has been less than that of natural gas. At least two factors may be contributing to this. First, the investment boom in more efficient gas-fired generation during the period 1999 to 2002 has led to improvements in average generating fuel efficiencies. Second, natural gas-fired generators make up only a portion of the generation in the region, and such generators are on the margin (i.e., setting the market-clearing price) only a portion of the time (18% of the time in 2000 rising to 26% in 2005).

The separation among average zonal prices grew from 2004 to 2005. Western region prices are consistently lower than the eastern and southern region prices. If there were no transmission constraints, the unconstrained transmission flows would reduce or eliminate the differences among the zonal prices. However, the separation in zonal prices between the western and eastern region prices suggests that growing transmission congestion and losses prevent this gap from closing.

PJM's Market Monitoring Unit (MMU) finds that PJM has "serious market structure issues" because too few sellers own substantial shares of supply in many of PJM's local markets. PJM's energy markets are moderately concentrated overall. PJM's capacity markets and ancillary services markets are highly concentrated. This suggests that PJM will continue to find it necessary to mitigate market power through offer capping and other measures. This effort to mitigate market power, which does not clearly distinguish whether high prices are cause by market power or by true economic scarcity, does not improve the PJM's attractiveness for generation investment.

In spite of moderate to high concentration of generation ownership, PJM finds that market participants behaved competitively in both 2004 and 2005. Because these were years in which capacity was generally abundant relative to load, the opportunities to exercise market power were limited, with the main scarcity-related problems occurring in load pockets. A better test of the robustness of competition may occur in a future year when capacity becomes tighter.

The Midwest ISO began operating in February 2002, and began its Day 2 Market in April 2005. A key feature of the Day 2 Market is its locational marginal price (LMP) for energy, by which the price of energy may be different at each power system location.

The Midwest ISO presently lacks markets for ancillary services. In imitation of PJM, it proposes to create markets for regulating reserves and contingency (spinning) reserves, with simultaneous co-optimization of energy and ancillary service markets. With both energy and reserve markets, more generators would commit themselves (i.e., start up) than is the case with only energy markets. Reserve markets could thus provide market-based incentives for generator commitment.

Because of the absence of reserve markets and because energy prices are often set according to the costs of infra-marginal units rather than according to those of peaking units, the Midwest ISO makes special payments (Revenue Sufficiency Guarantee payments) to generators to induce them to commit themselves. These payments were a hefty $600 million in 2005. A significant portion of these payments were made to maintain reliability in load pockets. The Midwest ISO has acknowledged that there are problems with the RSG and has begun the process to make changes to the market design to address those issues. With the creation of reserve markets and improvement in its energy pricing methods, the RSG payments should dwindle as they are replaced by more efficient pricing and cost allocation.

The Midwest ISO footprint has over 150 distinct owners of generation. Over the whole footprint, the market would therefore appear to be unconcentrated. Because of transmission constraints, competition is better assessed at the subregional level. The Midwest ISO's Central sub-region is moderately concentrated, while the East, West, and WUMS subregions are highly concentrated. In each of the latter three sub-regions, the top three suppliers control around 75% of supply. In the Central and West subregions, there are single pivotal suppliers in 20% of all hours, while in WUMS, there are single pivotal suppliers in more than 75% all hours. Consequently, the Midwest ISO finds that "the most significant potential competitive concerns in the Midwest are in the WUMS area."

During 2005, there were active broad constrained area (BCA) constraints with at least one pivotal supplier in two-thirds of the hours; and there were active narrow constrained area (NCA) constraints with a pivotal supplier in almost 30% of the hours. Hence, there are substantial local market power issues associated with both types of constraints. Nonetheless, FERC recently enjoined the Midwest ISO from mitigating market power problems associates with BCA constraints.

The Midwest ISO's energy market seems to be operating efficiently. First, there is a general convergence between the Midwest ISO's *ex ante* and *ex post* real-time prices. Second, the Day-Ahead Market has been an accurate predictor of real-time conditions: excluding the effects of the Ludington Pumped Storage facility, Day-Ahead scheduled MWs have been within 1% of Real-Time scheduled MWs. The convergence of day-ahead and real-time prices is partly attributable to the active market in day-ahead virtual trades. Indeed, "almost all of the price-sensitivity on the demand side in the day-ahead market is provided by the virtual traders rather than by physical loads." Despite its significant benefits in promoting the efficiency of the Midwest ISO's energy markets, virtual trading may have been significantly damaged recently by FERC's decision to impose RSG charges on virtual transactions.

On the other hand, the Midwest ISO market is biased in a manner that encourages load to under-schedule in the day-ahead market. Because of market design flaws, day-ahead loads have been consistently less than real-time loads. Peaking units set prices when their bids are accepted in the day-ahead market; but if their operational inflexibility makes them unresponsive to small changes in loads, they do not set prices in the real-time market. Furthermore, the real-time market's performance is also compromised by generators offering to the market less than half of their apparent operational flexibility. This withholding of flexibility raises the costs of generating electricity, and can also create or exacerbate transmission constraints.

Although generators in the Midwest ISO *have* market power, several pieces of evidence indicate that their behavior was competitive during 2005. Generator outage rates were consistent with those of previous years. Deratings and outages were about the same under peak load conditions as they were otherwise; and the deratings of the largest suppliers were generally lower than those of other suppliers. Bids that appear excessively high were low in quantity. And generators produced for the market all but a couple percent of the power that appeared to be economic in each hour.

3. GENERATION INVESTMENT AND ADEQUACY

In this section, we report on recent generator-related reliability risks, on whether recent prices have been sufficient to induce new entry and induce continued operation of existing generation plant, and on investment trends. We begin with an overview of national trends, and then we look at each RTO market.

3.1. Overview of U.S. Trends 2000 to 2004

3.1.1. Generation-Related Reliability Risks

Generation-related reliability risks arise when there is a chance that generation capacity will not be sufficient to serve all load. Because transmission constraints limit the deliverability of power from generators to loads, generation-related reliability risks also depend upon the locations of generators relative to loads.

In general, the risk of generation shortages is related to generation reserve margins, which are the amounts by which generation capacity exceeds load. Even if the reserve margin is positive, so that generation capacity exceeds loads, there can be a risk of shortages because of unexpected events, namely generator outages or unexpected load increases. Consequently, the larger reserve margins are, the less likely that a generation shortage will occur.

Reserve margins are measured in different timeframes. In a longer timeframe, *planning reserve margins* are the amounts by which total generation capacity exceeds peak loads. Most regions of the U.S. seek planning reserve margins in the 15% to 18% range—that is, system operators like generation capacity to exceed peak loads by at least 15% to 18%. In a shorter timeframe, *operating reserve margins* are the amounts by which the available generation capacity at any moment in time exceeds load at that time. "Available capacity" is capacity that is not withdrawn from service due to maintenance, mechanical breakdown, or other circumstances, and that can produce power within some short timeframe (like thirty minutes). Most regions in the U.S. have operating reserve requirements in the neighborhood of 6% of contemporaneous load.

Table 19 shows planning reserve margins for several major regions of the U.S. in 2004. Except for the Midwest, all regions had surplus generation—that is, planning reserve margins in excess of the 15% to 18% target.[154] This occurred because the U.S. built more generating capacity between 2000 and 2004 than in any earlier five-year period. Almost all of this capacity is

[154] The WUMS sub-region of the Midwest ISO is a counter example where capacity shortages are predicted to occur as early as 2008 if no new generation or transmission capacity is built for the sub-region.

combined cycle gas plants, which are far more fuel-efficient than earlier gas plants. Independent generating companies built most of this capacity, while traditional utilities built less than a quarter of it.

Table 19
Planning Reserve Margins by Area, 2004[155]

Region	Summer Reserve Margin
New England	30%
New York	25%
PJM	36%
Midwest	16%
Southeast	32%

Region	Summer Reserve Margin
SPP	20%
ERCOT	26%
Northwest	23%
Southwest	29%
California	22%

Although the nation as a whole has access to more electric power generation than it needs, some local areas (i.e., load pockets) suffer from underinvestment. This can lead to local shortages of generation, with an accompanying risk of generation-related customer outages.

A fuller review of generation adequacy issues would look at operating reserve margins as well as planning reserve margins. It is possible that data could be obtained that indicate the frequency with which operating reserve margins have fallen below target levels in each of the regions. We have investigated whether such data are in fact available, and have determined that at this time they are not available. This will be pursued for the next issue of the Report Card.

3.1.2. Net Revenue Analysis

Net revenue is a measure of whether generators are receiving competitive returns on invested capital, of whether market prices are high enough to encourage entry of new capacity, and (in extreme cases) of whether market prices are high enough to encourage continued operation of existing capacity. As an indicator of generation investment profitability, net revenue is thus a measure of overall market performance as well as a measure of incentives to add generation to serve energy markets.

Net revenue quantifies the expected contribution to capital cost received by generators from all markets, including energy, regulation, reserves, capacity, black start, and reactive power services. Ideally, this expectation should reflect generator operating constraints, planned outages, forced outages, environmental costs, and so on. Actual outcomes will, of course, differ from expectations. In addition, net revenue reflects the fact that for combustion turbines and other types of units typically deployed for peaking purposes, the high marginal costs and concomitant offer prices mean that these types of units are not called upon to produce energy for many hours of the year.

[155] FERC 2004 SOM Report, p. 59. Derived from NERC 2004 ES&D and RTO/ISO data. Reserve margins include uncommitted capacity not included in the regional profiles. They also include all derates, which may overstate the available reserves in some regions.

The generation surplus quantified by Table 19 has depressed energy market prices relative to costs for many new combined cycle plants, thereby reducing their profitability. Taken together, these factors, along with the dramatic rise in natural gas prices, help explain why many independent generating companies face financial difficulties and why many individual assets are financially distressed. On the other hand, although new gas units may be having difficulty recovering their full costs, non-gas-fired baseload and intermediate plants may be very profitable if they are receiving market-clearing prices based upon gas prices.

Table 20 provides additional evidence that price signals in recent years have not provided incentives for new gas-fired generation investments. This table shows the results of a net revenue test for each region of the country. Net revenue is computed by summing the market-related revenue streams a generator could have received in 2004, subtracting variable costs and comparing the result to the target revenue needed to pay for the fixed costs of a new plant.[156] The net revenue tests shown here differ from those that a regional entity might prepare in that price and cost estimates are drawn from the same sources for all regions. Among all the regions shown, only New York City has prices high enough to allow a new gas-fired generator to make a profit.

Table 20
Net Revenue for Combined Cycle and Combustion Turbines as a Percent of Target Revenue, by Region for 2004[157]

Region	Pricing Point	CC Net Revenue	CT Net Revenue
New England	Mass Hub	59%	NA
New York	NYC	285%	246%
	Hudson Valley	83%	27%
PJM	West Hub	34%	9%
Midwest	Cinergy	13%	0%
Southeast	Southern	32%	0%
SPP	SPP	32%	1%
ERCOT	ERCOT	30%	0%
Northwest	COB	48%	1%
Southwest	Palo Verde	48%	2%
California	SP-15	68%	3%
	NP-15	58%	1%

These results reflect the overall surplus of generation in the country. A natural outcome of the interplay of supply and demand is that net revenues should be low in such circumstances, reflecting the lack of need for investment.

[156] The estimates reported here include: a) spot market revenues for all hours when financially feasible to operate; and b) capacity revenues from RTO capacity markets, when relevant. The estimates do not include ancillary service revenues. "Variable costs" are fuel and variable operation and maintenance costs. The estimates reported here are based upon EIA cost estimates, which tend to be lower than many others.

[157] FERC 2004 SOM Report, p. 60.

Figure 24 shows the average monthly natural gas spark spread in PJM and adjacent markets for the years 2001 to 2005. The "spark spread" refers to the difference between electricity spot market prices for electricity at the generator's location and natural gas prices, where the spot market price for natural gas is expressed in equivalent terms through use of a specified heat rate of a gas-fired unit.[158] A positive spark spread indicates that the price of electricity was relatively high, meaning that producing electricity from gas would tend to be profitable; while a negative spark spread indicates that the price of electricity was relatively low, meaning that producing electricity from gas would tend to be unprofitable.

Figure 24
Natural Gas Spark Spread in Selected Eastern Markets, 2001 – 2005[159]

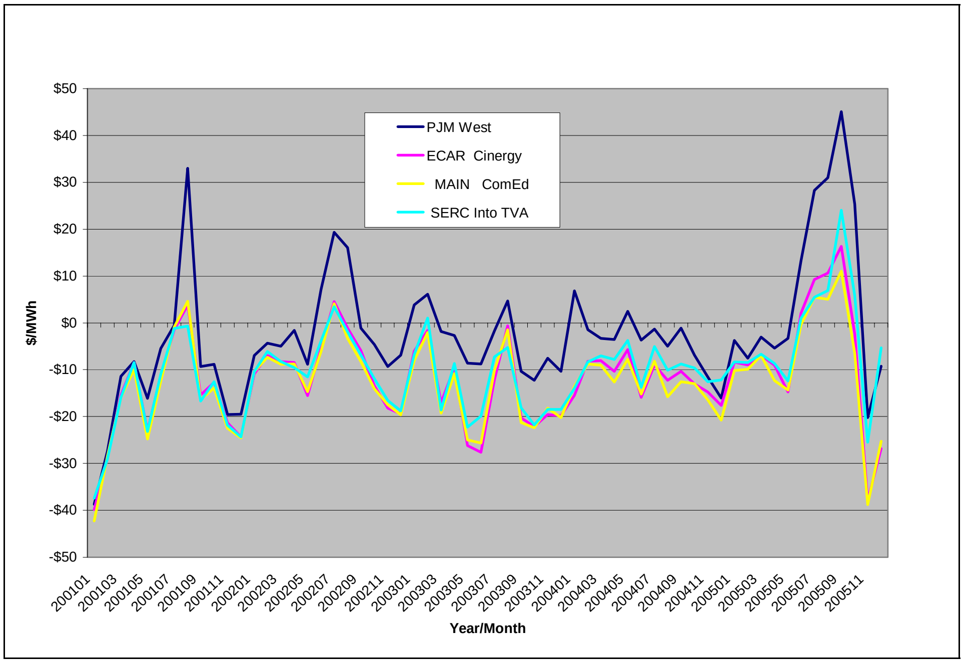

Figure 24 shows that, for most of the period, the spark spread in PJM was positive (even more so in the summer to fall period of 2005), averaging just under $3/MWh at the PJM Western Hub. The spark spread in the other markets was less encouraging, with averages over the five years ranging from negative $4.90/MWh for SERC into TVA to negative $7.40/MWh for ComEd. As an indicator of the profitability of gas-fired generation, the spark spread in Eastern markets does

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[158] Natural gas prices are converted from $/MCF to a $/MWh equivalent by converting MCF to BTU and then BTU to MWh. The conversion factors are mmBTU equals MCF/1.027 and MWh trend from 9.4 to 8.0 MMBTU. The MCF to BTU relationship is obtained from EIA, *Natural Gas Weekly*, 1/19/06 (also *Annual Energy Review*, Table A4). The BTU to MWh relationship are national average natural gas heat rates from 2001 – 2004 as reported by EEI (http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile1_1.xls.) EEI shows the heat rate trending downward from 10.4 to 9.3 MMBTU/MWh, a decline of 3.7% per annum. We estimate a 2005 heat rate on the basis of this trend and assume that marginal heat rates in PJM are 100% of the national average heat rate.

[159] Electricity price data were obtained from the Energy Management Institute and the PJM website. The natural gas price series for 2001 through 2005 (referred to as the Natural Gas Electric Power Price series) were obtained from the EIA website.

not appear to have presented investors with an encouraging signal for investment in gas-fired generation over this five-year period, with the possible exception of PJM.

Figure 25 shows the "dark spread," which is the difference between the spot market price of electricity and the spot price of coal, where the spot market price of coal is expressed in equivalent terms through use of a specified heat rate of a coal-fired unit. A high dark spread indicates that the price of electricity is relatively high, meaning that producing electricity from coal is particularly profitable; while a low dark spread indicates that the price of electricity was relatively low, meaning that producing electricity from coal is less profitable.

Figure 25
Dark Spread for Selected Eastern Markets, 2001 – 2005[160]

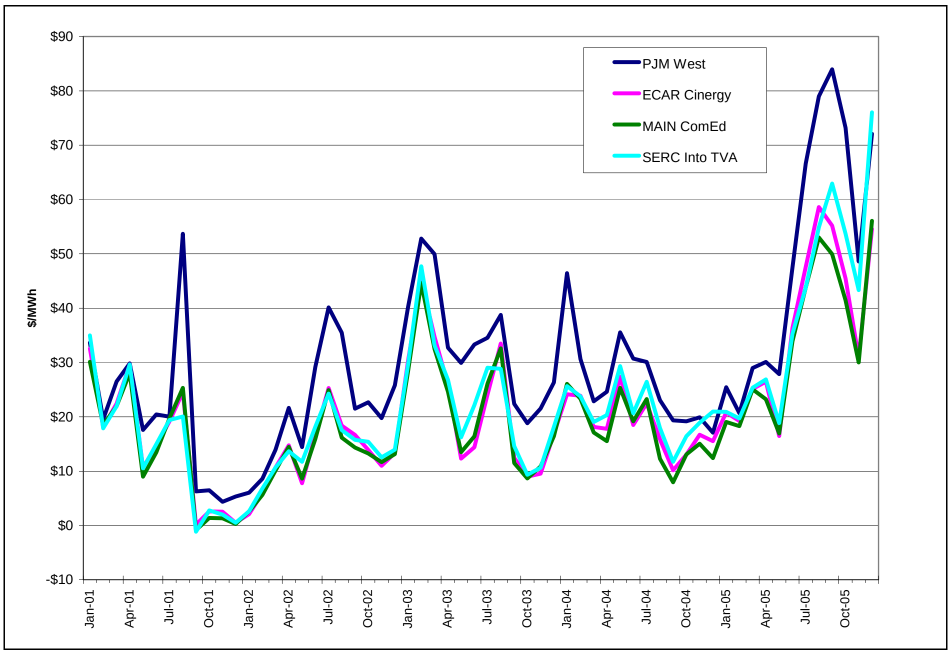

Figure 25 shows that the profitability of coal plants has varied substantially over time, reaching high levels during the natural gas price spike of 2005. The figure also shows that there is a significantly greater dark spread in PJM (based on the PJM Western Hub price) than in adjacent markets. For PJM's Western Hub, the average dark spread was just above $30/MWh over the past five years. Therefore, existing coal-fired power plants in PJM are likely to be profitable.

3.1.3. Investment Trends

Recent generation investments and planned generation investments indicate whether the market design and prices together promise that future reliability and prices will be acceptable.

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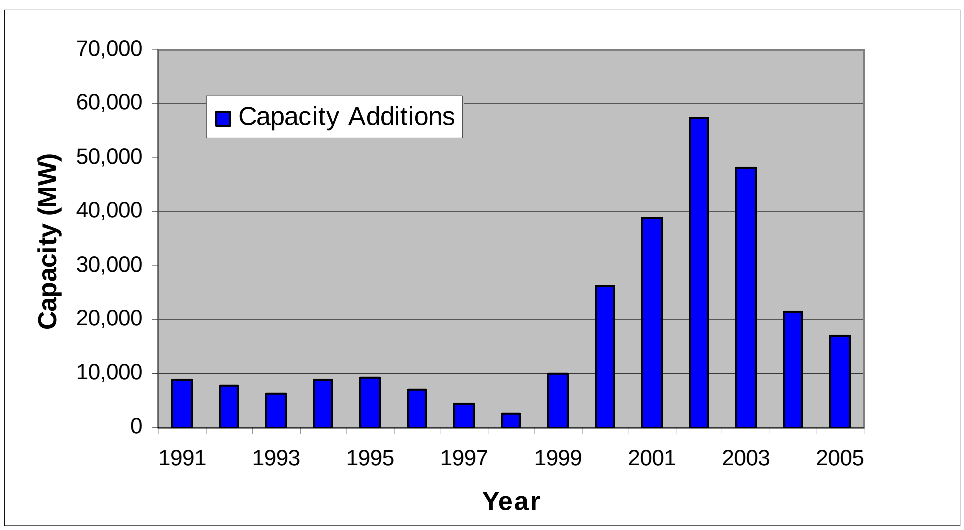
[160] Coal price series obtained from Platts. Dark spreads are computed in a manner similar to spark spreads. The conversion factors are 20 tons of coal per MMBTU and 10 MMBTU/MWh. Both conversion factors were obtained from EIA. Unlike natural gas, average heat rates for coal-fired units have showed little time trend during the 2001 – 2005 period. Therefore we used a single number for all years.

Due to the recent and current surplus of generation that we are only now beginning to work off, market prices in recent years did not generally signal a need for new construction of generation, particularly of gas-fired capacity, in any of the regional markets. What there was of new generation announcements focused on coal-fired and renewable projects. Regulated utilities, their affiliates, and public power participants based a greater proportion of their investment decisions on a combination of current plant economics and the prospect of creating hedges against projected load growth.

Figure 26 shows a falling trend in generation capacity additions during the 2002 – 2004 period following the significant increase from 1998 to 2002. The 25 GW of generating capacity added in 2004 was only half of that added in 2003, as might be expected with the current reserve margins. Additions in 2005 were even lower.

Independent power producers (IPPs), who sponsored 7.7 GW of the generation that reached commercial operation in 2004, had a larger share of new generation than any other group of investors. Utility-affiliated power producers (APPs) and IOUs were more active in their construction programs than they had been in the recent boom period (1999 – 2002). APPs built just over 6 GW, or 27% of total new generation. Investor-owned utilities built 18% of the new capacity in 2004. Municipals and cooperatives placed into service 11% of the new capacity. Lenders completed 2 GW of generation projects that were turned over by financially troubled sponsors, comprising 9% of the new generation.

Figure 26
U.S. Generating Capacity Additions, 1991 – 2005[161]



As shown in Figure 27, gas-fired generation dominated additions in all regions.[162] Most additions were built in PJM, the Southeast, and the Southwest, where markets were already

[161] FERC 2004 SOM Report, p. 28. Derived from EIA's *Electric Power Monthly* Table ES_3 and Platts Powerdat data, as of March 10, 2005 and recent assessment by Apache Corporation (Apache), obtained at http://www.apachecorp.com/Explore/Articles/200601/Topic_Report_New_Power_Generating_Capacity/. Apache's report puts the additions for 2005 just below 20,000 MW.

[162] Approximately 250 MW of renewable capacity was added, primarily in the Midwest.

experiencing regional overbuild conditions. When measured as a percentage added to installed summer capacity by the new construction, PJM added almost 10% and the Southwest added over 5%. These new additions increased excess capacity, adding downward pressure on both energy and capacity prices in the market, and reducing net revenues for new gas-fired capacity in most regions during the assessment period.

Figure 27
U.S. Generating Capacity Additions by Fuel Type and Region 2004[163]

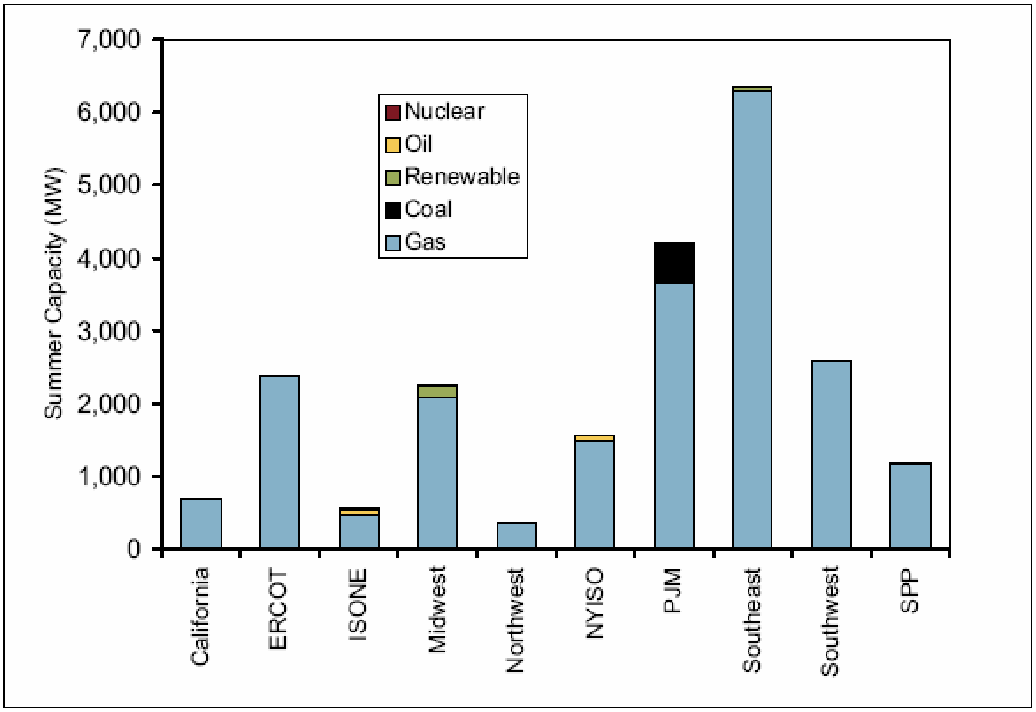


Figure 28 shows the geographic diversity by ownership class for generation investments in 2005.[164] The area with the greatest investment was the Southeast, particularly in Florida, which faces some congestion. California and the Midwest witnessed relatively high levels of investment and showed increases over 2004 levels; California investment more than tripled and Midwest investment nearly doubled from 2004 levels. New England had no identifiable additions, and the capacity additions in PJM were mainly renewables that were not attributable to the sponsor types shown in the figure. Overall, about one third of all additions appear to have been made in areas that are constrained and face transmission congestion, particularly California, Wisconsin, and downstate New York.

Figure 28
Generation Investment by Region and Ownership Type, 2005[165]

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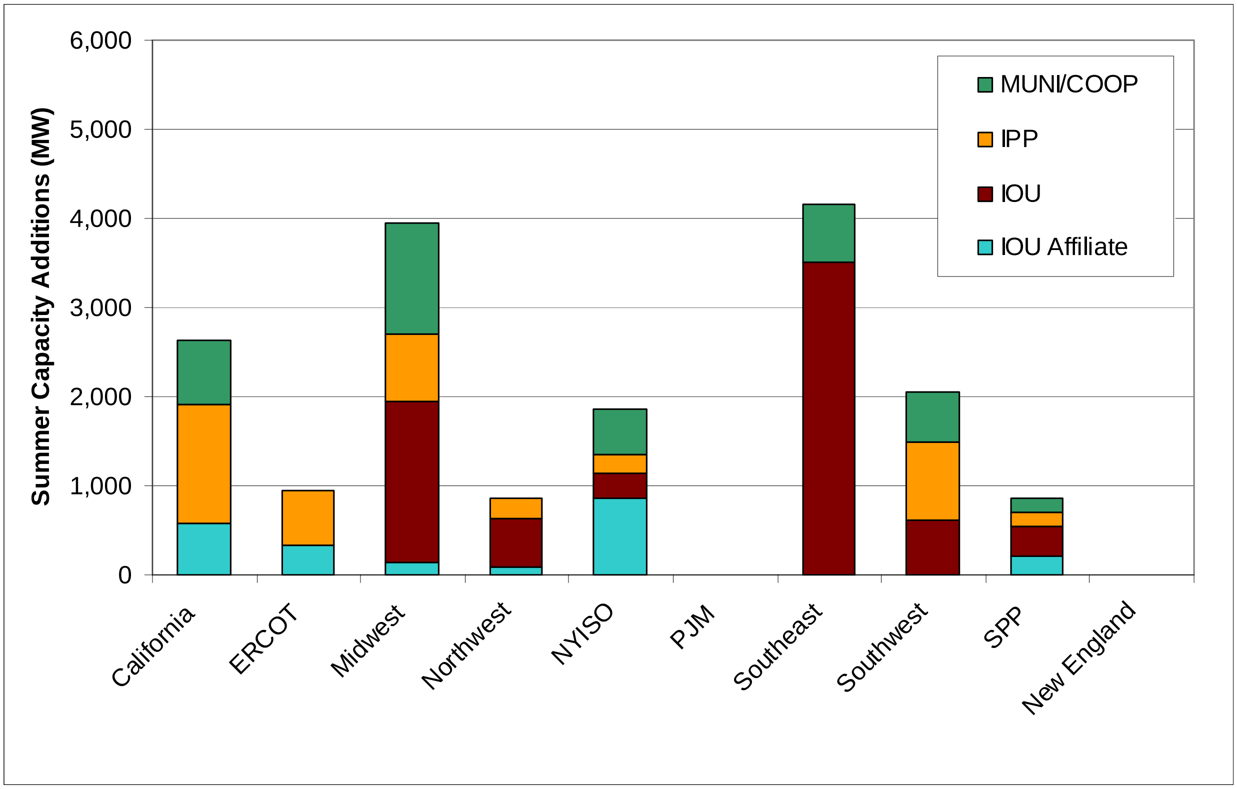
[163] FERC 2004 SOM Report, p. 29. Derived from EIA and Platts data, as of March 10, 2005.

[164] FERC, *Winter 2005-2006 Energy Market Update,* Item No. A-3, February 16, 2006, a presentation to the FERC Commissioners by Commission staff. Obtained at http://www.ferc.gov/legal/staff-reports/eng-mkt-con.pdf.

[165] FERC, *Winter 2005-2006 Energy Market Update.*



Municipals and electric cooperatives added just under 4 GW, slightly less than in 2004. IOUs added 7 GW in 2005, almost doubling their 2004 investments. Their affiliates added slightly over 2 GW, a little more than a third of what was added in 2004. IPPs added more than 4 GW, down from 2004.

Patterns of investment differed across the regions. In the Southwest, nearly all generation investment was made by electric cooperatives, municipalities, and IOUs. Investment by IPPs occurred in California, the Southwest, Texas, and the Midwest.

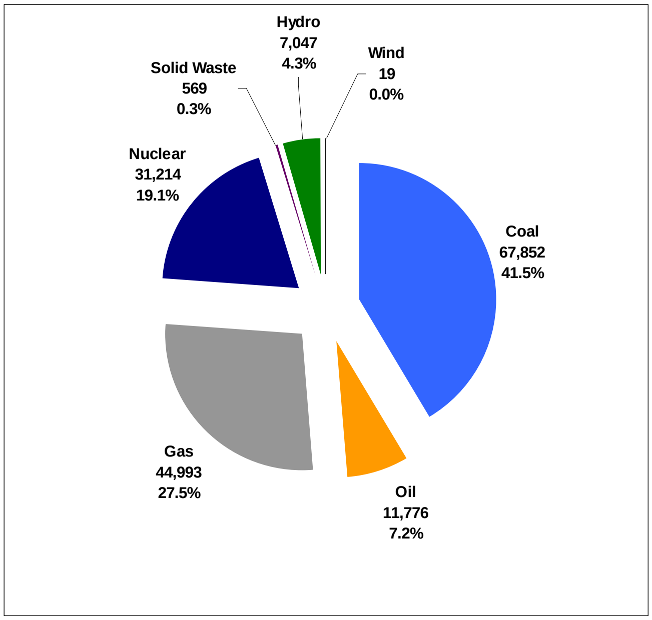
Generation additions are expected to decline further in 2006. Future investments are expected to focus increasingly on baseload coal, nuclear and renewables. Regional trends in investment by fuel and investor type are not clear.[166]

[166] All figures and descriptions in the preceding paragraphs in association with Figure 22 have been obtained from FERC, *Winter 2005-2006 Energy Market Update*.

3.2. PJM

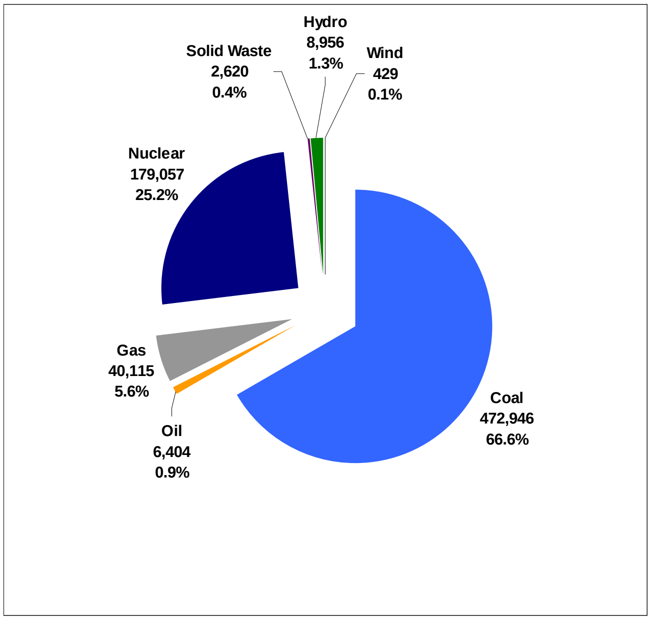
Figure 29 shows PJM's capacity at the end of 2005, including the division of that capacity among fuel sources. Figure 30 shows PJM's generated energy in 2005, again by fuel source. Coal, gas, and nuclear provide the largest quantities of capacity, in that order; but coal and nuclear provided the largest quantities of energy, while gas ranks a distant third in energy production, primarily because gas units are typically used for peaking. There is also significant oil and hydro capacity, though this capacity provides very little energy.

Figure 29
PJM Capacity (MW) by Fuel Type at December 31, 2005[167]



167 PJM 2005 SOM Report, Figure 3-4, p. 135.

Figure 30
PJM's Energy Generation (MWh) in 2005[168]



3.2.1. Net Revenue Analysis

As shown in Table 19, PJM is the region that has been most affected by the recent overbuilding of generation capacity. Among all of the regions, its planning reserve margin in 2004, at 36%, was the highest of all of the regions. At least in part because of this surplus capacity, PJM believes that, over the past six years, its prices have not been sufficient to allow most types of new generation units to fully recover their annualized capital and operating expenses.

> "…net revenue has been below the level required to cover the full costs of new generation investment for several years and below that level on average for new peaking units for the entire market period. The fact that investors' expectations have not been realized in every year could be taken as a reflection of cyclical supply-demand fundamentals in PJM Markets. However, it is also the case that there are some units in PJM, needed for reliability, that have revenues that are not adequate to cover annual going forward costs and that their owners, therefore, wish to retire. This suggests that market price signals and reliability needs are not fully synchronized… The level of net revenues in PJM Markets is not the result of the $1,000 per MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition… However, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the

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[168] PJM 2005 SOM Report, Figure 3-5, p. 136.

> Energy Market alone frequently does not directly value the resources needed to provide for reliability."[169]

Annual net revenue from energy for gas-fired technologies in 2004 in the entire PJM footprint was below the five-year average for the second consecutive year. For a combined cycle (CC) unit, revenue from energy increased 1.1% from 2003 but was still 26.7% below the five-year average. For a combustion turbine (CT), revenue from energy reached a five-year low, declining from $9.76 per kW-year in 2000 to $0.05 per kW-year in 2004. For the Western Hub of the PJM RTO, net revenue as a percent of target (breakeven) revenue is estimated to be 34% for a CC unit and 9% for a CT.

In 2005, new peaking and midmerit units would not have been able to fully recover their annualized costs, but new coal-fired baseload units would have been profitable.[170] This outcome comports with expectations in the face of such a significant capacity surplus in PJM.

Estimates of the cost of new entry in PJM vary slightly. For example, PJM estimates were higher than the EIA-based estimates above: $93.55 per kW-year for a new CC and $72.20/kW-year for a new CT. According to a Strategic Energy Services Inc. report, new-entry costs for a CT in New Jersey are estimated at $72.21 per kW-year, slightly lower than for a CT in Maryland or Illinois at $74.12/kW-year and $73.87 per kW-year, respectively.[171] Estimated PJM 2004 net energy revenues fell well below all of these thresholds. The addition of estimated net revenue from selling into capacity markets made little difference in the results. Without significant net revenue from energy, capacity, and ancillary services, market-based investment was not receiving strong positive signals in the PJM RTO region.

PJM's provides its own estimates of the profitability of several types of generating units. PJM's findings are replicated in Tables 21, 22, and 23 for a natural gas-fired combustion turbine (CT) generator, a two-on-one natural gas-fired combined cycle (CC) generator, and a conventional coal plant (CP), single reheat steam generation plant. The basic story is that all of the units would have lost money over the last several years, but baseload units would have fared better than peaking units. For example, as shown in Table 23, new baseload coal units under economic dispatch would recover 110% of the 20-year levelized fixed costs. If this dramatic improvement were to continue in 2006, it is possible that investment in coal-fired generation may be renewed in PJM. The fact that new coal-fired units would have been profitable in PJM in 2005 implies that existing coal-fired generation must also have been profitable.

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[169] PJM 2004 SOM Report, p. 85.

[170] PJM 2005 SOM Report, p. 29.

[171] The report was obtained at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20050423-som-cone-ct-cc-coal-summary.pdf.

Table 21
20-Year Levelized Fixed Costs Versus Dispatch Revenues – CT
($ per MW-year)[172]

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$80,990	112%	$74,537	103%
2000	$72,207	$38,924	54%	$30,946	43%
2001	$72,207	$72,477	100%	$63,462	88%
2002	$72,207	$36,996	51%	$28,260	39%
2003	$72,207	$19,956	28%	$10,565	15%
2004	$72,207	$15,687	22%	$8,543	12%
2005	$72,207	$20,037	28%	$10,437	14%
Average	$72,207	$40,724	56%	$32,393	45%

Table 22
20-Year Levelized Fixed Costs Versus Dispatch Revenues – CC
($ per MW-year)[173]

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$109,754	117%	$100,700	108%
2000	$93,549	$65,445	70%	$47,592	51%
2001	$93,549	$101,413	108%	$86,670	93%
2002	$93,549	$65,286	70%	$52,272	56%
2003	$93,549	$58,782	63%	$35,591	38%
2004	$93,549	$57,996	62%	$35,785	38%
2005	$93,549	$73,517	79%	$40,817	44%
Average	$93,549	$76,028	81%	$57,061	61%

Table 23
20-Year Levelized Fixed Costs Versus Dispatch Revenues – CP
($ per MW-year)[174]

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$126,097	61%	$118,021	57%
2000	$208,247	$138,141	66%	$134,563	65%
2001	$208,247	$140,776	68%	$129,271	62%
2002	$208,247	$116,648	56%	$112,131	54%
2003	$208,247	$176,138	85%	$169,510	81%
2004	$208,247	$144,908	70%	$133,125	64%
2005	$208,247	$237,870	114%	$228,430	110%
Average	$208,247	$154,368	74%	$146,436	70%

172 PJM 2005 SOM Report, Table 3-12, p. 130.

173 PJM 2005 SOM Report, Table 3-13, p. 130.

174 PJM 2005 SOM Report, Table 3-14, p. 130.

Based upon an expectation that the losses of the past several years will continue into the future, especially for peaking units, the PJM Board of Managers has been concerned that power system reliability will be compromised by insufficient generation investment in at least some locations within the PJM footprint.

> "The Board is of the view that reliability may be compromised in PJM in the absence of a viable capacity model… [U]nless specific steps are taken to retain existing generation or add new generation investment and/or regional transmission, reliability may be compromised in the Eastern section of the PJM Region as early as 2008."[175]
>
> "The Board is of the view that the current capacity and energy markets are not adequate to secure continued generation adequacy."[176]

The PJM Board believes that the present capacity market has been insufficient to address the generation adequacy problem.

> "The experience over the last six years has shown that while the capacity market has provided a mechanism for the short-term exchange of capacity resources, the capacity market has not provided a price signal consistent with long term reliability and locational differences in long term reliability. The current capacity market has instead acted as a short term measure of the value of generation in a time of overall excess supply and has resulted in a significant undervaluation of capacity as a component of preserving system reliability over the long-term on a location specific basis."[177]
>
> "In short, experience has shown that the daily capacity market simply does not conform to the reality that generation is a long term reliability requirement. It is the Board's conclusion that short term capacity markets by their very structure do not provide the appropriate market value signals for a long term reliability requirement and do not capture the lead time necessary to plan, construct, and install generation plant. The Board also has concluded that reliance on energy market scarcity prices to encourage new investment is not the right solution."[178]

The PJM Board believes that part of the solution lies in reform of the capacity market.

> "The Board also believes that an appropriately designed capacity market will encourage bilateral transactions and that the presence of an active bilateral capacity market is part of the solution."[179]

This belief underlies the proposed Reliability Pricing Model (RPM) capacity market described in greater detail in Sections 2.1.2 above and 3.2.3 below.

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[175] P.G. Harris, President and Chief Executive Officer of PJM Interconnection, LLC, Letter to PJM Members Committee and Stakeholders, March 22, 2005, p. 3.

[176] *Ibid.*

[177] *Ibid.*, p. 4.

[178] *Ibid.*

[179] *Ibid.*

3.2.2. *Investment Trends*

Capacity is being built in PJM at an average rate of a few thousand MWs per year. Table 24 presents statistics for recent years. Because of time lags between planning and construction, the additions in each year reflect investors' market expectations of a few years prior to when the additions are completed. These additions are rather small relative to PJM's total capacity of 163,471 MW at the end of 2005. In the long run, such a volume of additions will not be sufficient to meet load growth and replace aging capacity. In particular, PJM had 3,560 MW of generation retirements in the twelve months ended September 30, 2005.[180]

Table 24
PJM Capacity Additions, 1999 – 2005[181]

Year	Additions (MW)
1999	38
2000	230
2001	915
2002	5,350
2003	3,712
2004	3,106
2005	2,892

At the end of 2005, there were 24,348 MW of capacity queued for addition through 2010. (Over this same five-year period, the weather-normalized summer peak load in PJM is expected to grow at the rate of 1.7% or 2,000 MW annually, from 115,166 MW in 2005 to 125,294 MW in 2010.[182]) Table 25 summarizes the generation in this queue by technology and control area. If all of this capacity were built, additions over the next five years would be nearly 5,000 per year; but inevitably, only a part of this capacity will actually be constructed within the five-year timeframe. Because a large share of this capacity is slated to occur in the western part of PJM while the need for the power from this capacity is mostly in the eastern part of PJM, there is some question about its deliverability to customers.

Furthermore, generation retirements are a serious issue. Figure 31 shows the capacity retirements relative to additions for the past four years. PJM has 9,800 MW of generation that is over 50 years old, and another 19,500 MW that is between 40 and 50 years old. After years with practically no retirements in the PJM Mid-Atlantic region, late 2003 and 2004 saw an upsurge in notifications to PJM from owners that planned to retire units. PJM received 58 requests to deactivate units during 2004. In response to these requests, PJM now has a formal FERC-approved retirement policy that requires generators to notify PJM of planned retirements 90 days before they take effect, and that requires PJM to respond with an estimate of effects on reliability

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[180] PJM 2005 SOM Report, p. 56.

[181] PJM 2005 SOM Report, Table 3-16, p. 137.

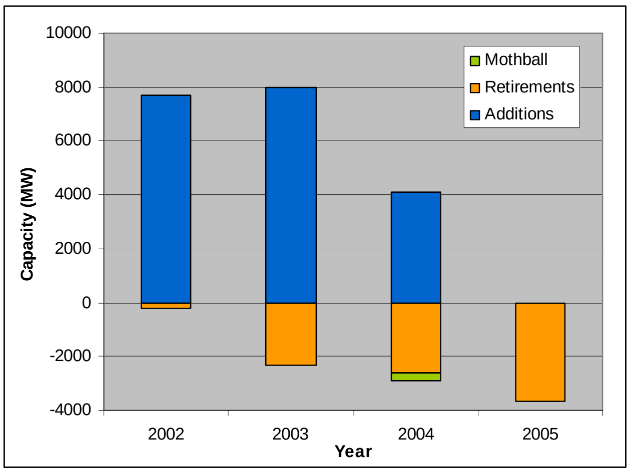
[182] PJM, "Regional Transmission Expansion Plan," Section 2, February 22, 2006, p. 15.

within 30 days of the notification. If the retirement poses a reliability risk, the policy provides for a mechanism to reimburse the owner for the cost expended to continue operation.[183]

Table 25
PJM Capacity Queue at December 31, 2005[184]

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Steam	Wind	Total
AECO	966	122	2	0	0	8	1,098
AEP	634	179	0	147	5,560	0	6,520
AP	640	0	23	0	1,122	1,451	3,236
BGE	0	0	5	0	0	0	5
ComEd	0	0	0	0	600	5,309	5,909
DAY	0	0	0	0	0	48	48
Dominion	1,275	0	29	431	0	0	1,735
DPL	0	0	13	0	1	0	14
JCPL	0	0	14	0	0	0	14
PECO	1,301	0	2	0	0	0	1,303
PENELEC	0	0	0	0	125	1,295	1,420
PEPCO	0	14	0	0	0	0	14
PPL	0	0	53	0	0	555	608
PSEG	2,351	55	7	0	0	11	2,424
Total	7,167	370	148	578	7,408	8,677	24,348

Figure 31
PJM Generation Additions, Retirements and Mothball Units
2002 – 2005[185]



[183] PJM Open Access Transmission Tariff, Section V.

[184] PJM 2005 SOM Report, Table 3-21, p. 142. Company names are as follows: Atlantic Electric Company, American Electric Power, Allegheny Power, Baltimore Gas and Electric, Commonweatlh Edison, Dayton Power and Light, Dominion Virginia and North Carolina Power, Delmarva Power and Light, Jersey Central Power and Light, PECO Energy Company, Pennsylvania Electric Company, Potomac Electric Power Company, PPL Electric Utilities Corporation, and Public Service Electric and Gas Company.

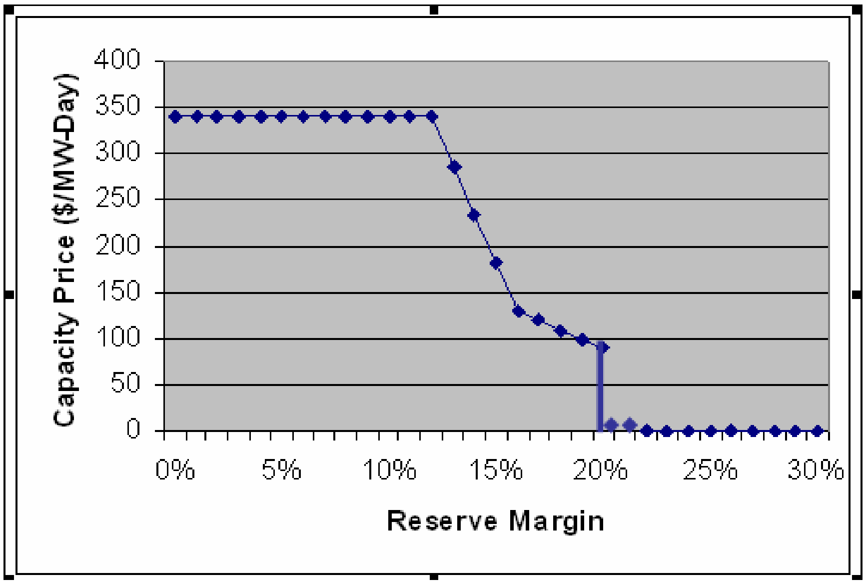
[185] FERC 2004 SOM Report, p. 112 for years 2002 to 2004. Source for 2005 retirements is *PJM Deactivations and Deferrals (As of April 10, 2006)*, obtained at http://www.pjm.com/planning/project-queues/gen-retirements/20060410-pjm-gen-retire-list-public-deactivated.pdf .

3.2.3. The Reliability Pricing Model

The purpose of the RPM is to encourage generation, transmission, and demand-side investments, and to encourage them to locate in the right places. To recognize the time required to make new investments operational, PJM will conduct a "Base Residual Auction" four years prior to each Delivery Year. This auction will address those capacity needs that LSEs do not expect to meet from their already owned or contracted resources. Prices will reflect transmission constraints as well as load following or quick-start reserve service needs.

Locational capacity prices would be set on the basis of locational and operational reliability constraints, the submitted supply offers, and a Variable Resource Requirement ("VRR") curve that operates as a proxy for a capacity demand curve. The downward sloping VRR curve is illustrated in Figure 32 below.

Figure 32
PJM Variable Resource Requirement Curve[186]



The VRR curve would set a locational price for capacity four years in advance that would, in effect, replace the current uniform, region-wide price. All resources with supply offers at or below the clearing price will be accepted in the auction and committed to provide capacity to the PJM system during the delivery year (i.e., four years hence).

Under the RPM proposal, the PJM region would be subdivided into zones, known as Locational Deliverability Areas ("LDAs") that are defined by the areas that, according to PJM's RTEP process, have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations. Thus, the capacity prices would vary by LDA when transmission is constrained. PJM also plans for the LDA capacity prices to be set on a seasonal basis.

[186] *Ibid*., p. 4.

In theory, the RPM proposal would allow capacity resource offers to be made from existing and planned generation resources, existing and planned load management programs ("Demand Resources") and, planned merchant transmission upgrades that provide incremental increases in import capability into constrained LDAs. Thus, by giving all types of resources an opportunity to make offers in the LDA auctions, the forward market design of the RPM intends to make the capacity market contestable.

In addition to the annual four-year forward auction, PJM plans to hold up to three additional interim auctions prior to the Delivery Year to provide market participants the opportunity to make adjustments to their capacity market positions because of changes to resource availability or because PJM projects that an LDA will be short of resources in the delivery year.

To ensure that committed resources fulfill their commitments during the delivery year, the RPM process would include compliance and deficiency charges. The RPM process would also include provisions designed to protect against the exercise of market power, including market structure tests, and offer caps based on avoidable-cost determinations.

Alternatives to the proposed RPM process that have been discussed include an "energy only market" and the use of call options.[187] An energy-only market allows the price of electrical energy to go as high as is needed to balance supply and demand (without any exercise of market power), thus obviating generators' need for capacity revenues. The call option approach would require LSEs to purchase a portfolio of call options, which might reduce spot price volatility while using the call option premium payment to stabilize generators' income, thereby enhancing investment incentives.[188]

3.3. Midwest ISO

Table 26 shows that planning reserve margins in the Midwest ISO grew between 2003 and 2004 as capacity increased slightly while loads fell slightly. Table 27 shows how the planning reserve margins vary by sub-region in 2004. Because planning margins are traditionally around 18%, all of the sub-regional margins were more than adequate.

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[187] A call option in electricity is a financial derivative that gives the buyer the right, but not the obligation, to buy a specified quantity of electricity for a specified price within a specified period of time in exchange for a one-time premium payment.

[188] See S. Oren, "Capacity payments and generation adequacy in competitive electricity markets," Proceedings of SEPOPE IIV Conference, Curitiba, Brazil, May 2000, pp. 22-26, and "Ensuring generation adequacy in competitive electricity markets," University of Chicago Press, 2005; and H.P. Chao and R. Wilson, "Resource adequacy and market power mitigation via option contracts," Proceedings of the POWER Conference, University of California Energy Institute, 2004.

Table 26
Midwest ISO Generating Capacity and Planning Reserve Margins, 2003 – 2005 [189]

	2003	2004	2005
Total Resources (MW)	131,162	132,933	142,025
Load (MW)	105,625	104,920	115,078
Resource Margin	24.2%	26.7%	23.4%

Table 27
Midwest ISO Generating Capacity and Planning Reserve Margins, by Sub-Region, 2004 – 2005 [190]

Year	Region[191]	Generating Capacity	Net Firm Imports	Load	Resource Margin
2004	ECAR	67,856	548	54,792	24.8%
	MAIN	27,302	(505)	20,493	30.8%
	MAPP	21,183	2,320	18,076	30.0%
	WUMS	12,954	1,275	11,559	23.1%
	Midwest ISO	**129,295**	**3,638**	**104,920**	**26.7%**
2005	East	44,195	2,409	38,397	21.4%
	Central	54,809	353	45,504	21.2%
	West	23,328	1,063	18,653	30.8%
	WUMS	14,685	1,184	12,524	26.7%
	Midwest ISO	**137,016**	**5,009**	**115,078**	**23.4%**

3.3.1. Net Revenue Analysis

Because of the surplus generation capacity in the Midwest, according to the Midwest ISO, "(t)he net revenue (revenues less production costs) produced by the energy markets was well below the levels necessary to invest in new generation."[192] This is illustrated in Figure 33, which shows revenues net of operating costs and hours of operations for combustion turbines and combined cycle units in each of the Midwest ISO's four sub-regions. The figure shows that neither type of generator was able to recover its capital costs in any sub-region, indicating that new generation investment would not have been immediately profitable. This lack of profitability is a reflection of the current generation surplus throughout the Midwest ISO: prices are properly signaling the fact that new generation is presently unneeded.

[189] Midwest ISO 2004 SOM Report, Table 2, p. 6 and Midwest ISO 2005 SOM Report, Table 1, p. 15.

[190] Midwest ISO 2004 SOM Report, Table 1, p. 5 and Midwest ISO 2005 SOM Report, Table 1, p. 15.

[191] The ECAR, MAIN, and MAPP regions of 2004 roughly correspond to the East, Central, and West regions of 2005. See Midwest ISO 2005 SOM, p. 10.

[192] Patton, Midwest ISO 2005 SOM, p. 5.

3.3.2. Investment Trends

The Midwest ISO region witnessed about 2,000 MW of capacity additions in 2004 and about 2,600 MW of additions in 2005. Table 28 shows the breakdown of this investment among Midwest ISO regions.

Figure 33
Net Revenues and Operating Hours of Midwest ISO Generating Capacity in 2005[193]

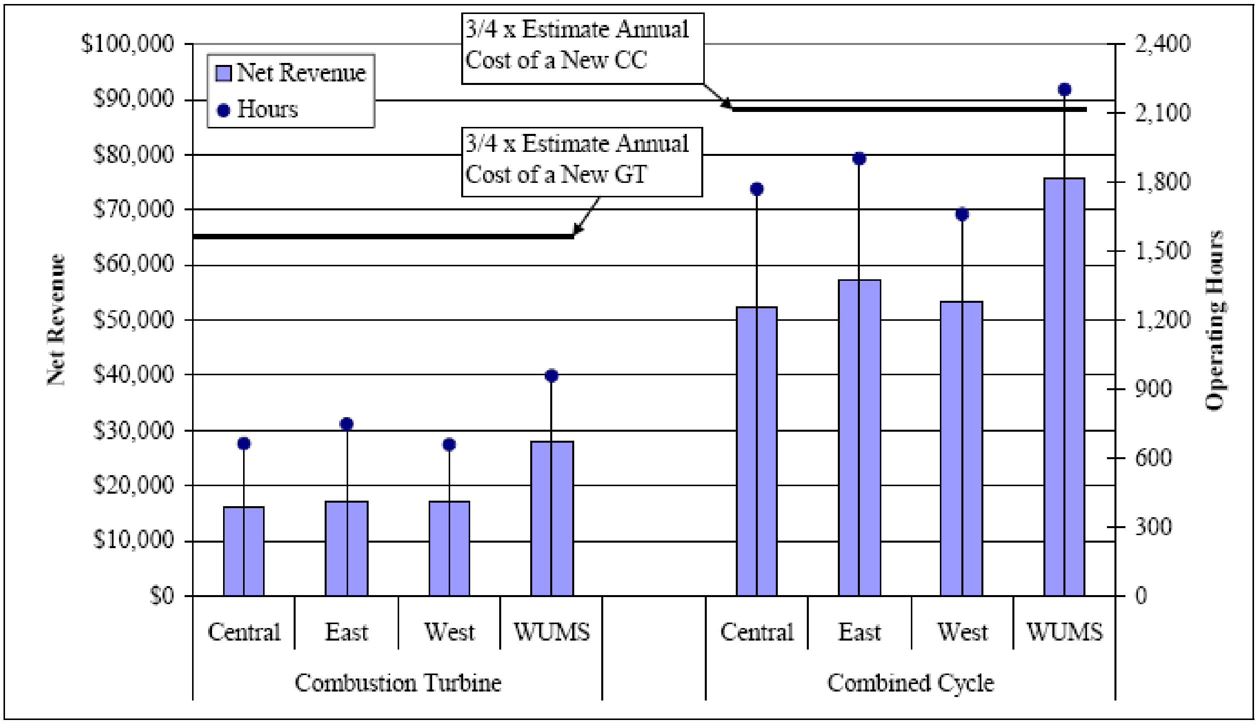

Table 28
Additions and Retirements of Midwest ISO Generating Capacity in 2005 [194]

Region	Additions	Retirements	Net Change
East	24		24
Central	135	13	122
West	1,301	16	1,285
WUMS	1,166		1,166
Total	2,626	29	2,597

[193] Midwest ISO 2005 SOM Report, Figure 6, p. 7.

[194] Midwest ISO 2005 SOM Report, Table 2, p. 16.

3.4. Third ISO

3.5. Summary and Implications

The U.S. power industry is still working off the generation surplus that arose from the irrational exuberance for gas-fired generation investments in the late 1990s and early 2000s. As of 2005, all regions except the Midwest had planning reserve margins in excess of their 15% to 18% targets.[195] Until natural gas prices spiked in 2005, resulting in high electricity prices whenever natural gas-fired units set the market electricity price, wholesale customers generally have benefited from the resulting downward pressure that this surplus exerts on market prices. At the same time, owners of natural gas-fired generation units generally experienced reduced profitability, thereby discouraging new gas-fired generation investment. With high gas prices, existing nuclear and coal-fired generation have generally been in an excellent position to profit substantially from the increase in market-clearing prices, in contrast to the situation that prevailed when gas prices were lower and market prices of electricity were apparently insufficient to induce substantial investment in new merchant coal-fired capacity.

There has thus been a falling trend in merchant generation capacity additions during the past few years which is likely to eventually result in higher market prices to consumers in future periods as the current excess capacity is absorbed into the market. The sharp rise in natural gas prices, the preponderance of gas-fired generation among the investments of the past decade, and the accompanying dearth of new baseload generation, is increasing the relative attractiveness of investments in non-gas technologies as the capacity surplus gets worked off.

The fundamental problem with market-based investments in power generation is the same as the problem with market-based investments in any other capital-intensive industry: imperfect market forecasts combined with long construction periods lead to market instability. When output prices are high, investors tend to over-invest, which can lead to a surplus and a price bust some years hence. When output prices are low, investors tend to under-invest, which can lead to a shortage and price spikes some years hence.

But for power generation, the problem is worse than in most other markets because the other markets generally have greater leeway in balancing supply and demand. For example, most capital-intensive industries, like the automobile industry, have the ability to store their products for some period of time. As another example, most capital-intensive industries, like the airline industry, have the ability to freely change the price of their services without running into major political and regulatory problems. Under regulation, the power industry balanced supply and demand by overbuilding generation capacity. The over-building occurred for several reasons: because generation capacity comes in discrete sizes that makes matching capacity to local load imprecise; because capacity was constructed to meet uncertain long-term load growth; and because regulation assigns a very high value to reliability. While overbuilding might be regarded as economically inefficient, the regulatory model did manage to provide reliable service at stable prices based upon cost-of-service, a result that consumers have tended to favor. A major challenge that RTOs face is to match that performance standard.

[195] The WUMS sub-region of the Midwest ISO is a counter example where capacity shortages are predicted to occur as early as 2008 if no new generation or transmission capacity is built for the sub-region.

In the current restructured power industry, the problem of balancing supply and demand can theoretically be solved by either unlimited price flexibility, or unlimited outages of those customers who lack contractual rights to sufficient supply at times of shortage, or assured cost recovery for generation investors. Since none of these three options appears to be politically feasible, the industry is heading for a solution that will most likely be some combination of these three options; but it is impossible to predict whether it will find a workable solution before the next crisis occurs.

In PJM, in part due to the surplus of capacity, market-clearing prices have induced a low level of new generation investment that PJM regards as a serious threat to reliability a few years hence. Additions of new capacity in the past couple of years have been offset to some extent by sizeable amounts of capacity retirements, a trend that is expected to continue into the future. Even though the PJM region as a whole currently has an abundance of generation capacity, it also has localized generation resource adequacy problems that arise primarily from transmission limitations.

PJM believes that the present capacity market design is contributing to the perceived lack of adequate investments in new generation capacity, implying that the capacity market needs reform. PJM's proposed solution, the Reliability Pricing Model approach, is a partial return to centralized planning and regulated generation prices and is therefore a move away from competitive market solutions. The PJM proposal has been very controversial among market participants and is now being litigated before FERC.[196] However, after a lengthy settlement process, PJM filed a settlement agreement with FERC in September 2006.[197]

In the Midwest ISO, the current resource adequacy requirement basically piggy-backs on the resource adequacy requirements of the states in which loads are located. Load-serving entities (LSEs) must meet these requirements according to the locations of their loads, not their resources. If a state lacks a resource requirement or has an indeterminate resource requirement, the Midwest ISO imposes an annual reserve requirement of 12% of the load located in that state. It does not appear that the Midwest ISO has penalties or other mechanisms by which it ensures compliance with its resource adequacy requirement.

Because of the surplus generation capacity in the Midwest, at the margin, according to the Midwest ISO, "(t)he net revenue (revenues less production costs) produced by the energy markets was well below the levels necessary to invest in new generation." In each of the Midwest ISO's four sub-regions, neither new combustion turbines nor new combined cycle units would have been able to recover their capital costs, indicating that new generation investment in these generation types would not have been immediately profitable. This lack of profitability for new and recent gas-fired investments is a reflection of the current generation surplus throughout the Midwest ISO footprint: prices are properly signaling the fact that new generation is presently unneeded. Nonetheless, the Midwest ISO region witnessed about 2,000 MW of capacity

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[196] A consultant for the Pennsylvania Office of Consumer Advocate has forecast that consumers would be paying between $3 and $4 billion per year more for generation capacity under the PJM proposal. See http://www.pennfuture.org/media_e3_detail.aspx?MediaID=189&TypeID=3.

[197] PJM, Settlement Agreement, September 29, 2006. FERC Docket No. ER05-1410 and EL05-148.

additions in 2004 and about 2,600 MW of additions in 2005.[198] The dark spreads in the Midwest suggest that existing coal-fired plants have been profitable, even though market-clearing prices may not yet be high enough to ensure that new coal-fired investments will be so.

4. TRANSMISSION INVESTMENT AND MANAGEMENT

This section describes the manner in which RTOs plan transmission, looks at transmission investment trends as a check on whether that planning process is actually delivering transmission additions to meet both reliability and economic needs, describes trends in transmission congestion costs, and looks at the extent to which transmission rights are available to offset those costs. We once again begin with an overview of national trends, and then we look at each RTO market.

4.1. Overview of U.S. Trends

4.1.1. Investment Trends

Recent transmission investments and planned transmission investments indicate whether the planning process is actually leading to acceptable levels of transmission investment.

About 931 miles of new transmission-lines of 230 kV or greater were built in 2004, an addition of roughly 0.6% of installed capacity (by mile). In contrast, more than 20 GW of new generation capacity entered operation, adding 2.3% to the electric generating fleet. The low level of transmission investment continued a trend that has persisted at least since the beginning of the 1990s. According to a study by Trimaran Capital Partners of FERC Form No. 1 data for the years 1992 – 2003, the annual growth in net investment in transmission plant by investor-owned utilities has averaged 2%. This growth contrasts with higher levels of load growth, generation, and distribution investment in the period. Trimaran's study showed that transmission's 30% of total transmission and distribution plant in service in 1992 declined to 26% of plant in service by 2003. Transmission additions varied significantly by reliability region, with no miles added in the footprints of the independent system operators of the Midwest, New England, or New York. Additions included 309 miles (1.3%) in the Pacific Northwest, 131 miles (1.7%) in the Southwest Power Pool (SPP), and 149 miles (0.4%) to the installed base in the Southeast.[199]

Transmission circuit miles are not a complete representation of all the investment in the transmission system. Substations, conductors, and other devices can also increase transmission capacity and plant in service. Transmission plant addition figures from FERC Form 1 data indicate a continued increase in transmission investment. Those data show a continuation of steady investment increases of 13.1% on a compound annual basis from 2000 through 2004. FERC Form 1 data for 2004 reflect preliminary filings.

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[198] Midwest ISO, *2005 State of the Market Report*. We have not determined how much of the capacity additions were by merchant generators.

[199] FERC SOM 2004 Report, p. 26.

Edison Electric Institute (EEI) data, based on a survey of historical and planned capital expenditures by EEI members, also indicate an increase in annual transmission investment. Specifically, EEI data show that transmission investment by investor-owned utilities averaged 12% annual growth from 1999 to 2003. In addition, the survey forecasts an unprecedented increase in transmission investment projected for the next few years (though plans do not always result in completed projects). The EEI survey results for projected expenditures in 2004 of $4.5 billion was close to the preliminary FERC Form 1 data for actual expenditures, which totaled $4.3 billion. The EEI survey published in 2005 projected gross transmission investment of $5.7 billion in 2005 growing to $6.1 billion by 2008. According to EEI, as quoted in the trade press, the actual investment was $5.8 billion.[200] While numbers on gross transmission investment do not reveal whether there has been a reversal of the previous trend for high-voltage transmission, the numbers suggest there may be a resurgence of investment that could contribute to closing the apparent gap.

In 2004, equity and debt markets rewarded stable, regulated operations with premium valuations. Thus, transmission investment gained new appeal to investor-owned utilities, which responded with increased plans to build. Nevertheless, successful execution of planned investment goals in the transmission sector can be difficult for several reasons:

- Developers face challenges in obtaining rights of way, siting, and licensing of electric transmission-lines. These challenges are typically even greater than those of the permitting process for gas pipelines and electric power plants.
- Regulatory uncertainty poses dilemmas. The uncertainty can be as specific as that related to rate treatment for a planned, delayed, or ultimately frustrated line. Or it can be as pervasive and general as the difficulty in distinguishing reliability from efficiency projects. The resolution of state and federal jurisdictional issues can, moreover, exacerbate cost recovery and cost allocation.
- Revenue uncertainty can reduce incentives in both regulated and merchant contexts. For merchant or contract generators, projecting future revenue and capturing the benefits of transmission investments can be difficult.

4.1.2. Congestion

Congestion occurs when available, low-cost energy cannot be delivered to all loads because of limited transmission capabilities. In such an event, higher-cost generating units must be dispatched in the import-constrained areas.

Data are currently not available to construct congestion trends for the country as a whole or for regions of the country that do not have centralized regional wholesale power markets administered by an RTO. Congestion trends (as represented by total costs of congestion) in those regions of the country that do have RTOs are shown in Table 29.

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[200] *Electric Utility Week*, 6/26/06, p. 1.

Table 29
Congestion Costs, Revenue, and System Redispatch Costs for RTOs[201]
(millions of dollars)

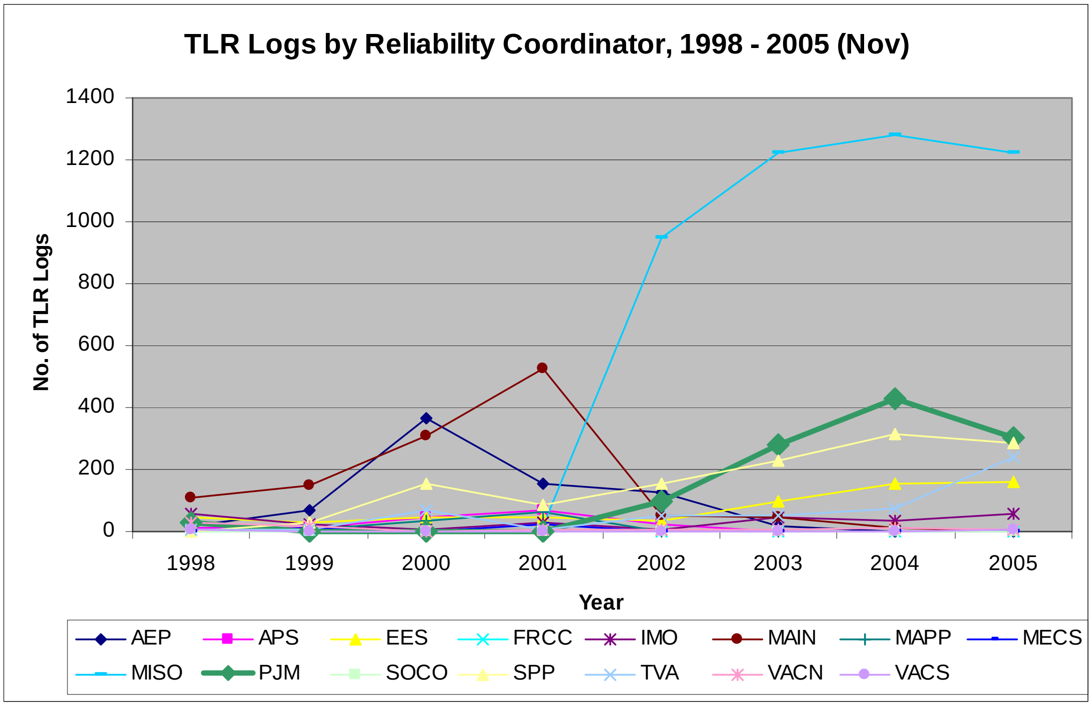
	California ISO	ISO New England	New York ISO	PJM	Midwest ISO
Year	(congestion costs)	(uplift charges)	(congestion costs)	(congestion costs)	(congestion costs)
1999	NA	99		65	
2000	391	120	517	132	
2001	107	100	310	271	
2002	42	75	526	453	
2003	26	50 – 300	689	464	
2004	56	100 – 200	629	750	
2005	35	266	685	2,092	563

Figure 34 shows the total MWh subject to Transmission Loading Relief (TLR) calls for several regions of the U.S. The Midwest ISO has had the most serious problems since 2001, though TLR calls have also risen for PJM.[202] The TLRs for the Midwest ISO are far more frequent than for any other region, and have been so since the Midwest ISO began operating in February 2002.

[201] California ISO, *Annual Report on Market Issues and Performance*, Department of Market Analysis, April 2005, p. 5-3; California ISO, 2005 FTR Congestion Revenues (April 1, 2004 through March 31), 2005.xls and 2006 FTR Congestion Revenues (April 1, 2005 through March 31, 2006).xls;.ISO New England, *2004 State of the Market Report*, inferred from Figures 25 and 26, pp. 43, ranges based on the interpretation of Uplift cost as defined by ISO New England; ISO New England, *2005 State of the Market Report*, p. 52;.New York ISO, Patton, 2004 Annual State of the Market Report: New York Electricity Markets, Presentation, May 2005, pp. 64-65, and New York ISO Annual_Metrics_Summary.xls. Values equal the sum of day-ahead and real-time congestion; and PJM 2005 SOM Report, Table 7-2, p. 249. The California figure for 2005 is based on FTR Revenues.

[202] The TLRs attributed to MAIN and AEP have fallen over time partly or primarily because their congestion management responsibilities have been assumed by the Midwest ISO and PJM, respectively.

Figure 34
TLR Calls (Level 2 or Higher) by Reliability Coordinator
1998 – 2005 (Nov.)[203]



4.2. PJM

4.2.1. Transmission Planning Process

PJM admits that its transmission planning process has goals that remain substantially unmet. The process divides transmission upgrades into those that are needed for reliability purposes and those that are needed for the "economic" purpose of reducing congestion costs. PJM makes sure that the reliability upgrades are built. The process for economic upgrades yields more indefinite results, as it relies on the following process:

> "The objective of the economic planning component of the regional transmission planning protocol is to provide cost-effective transmission solutions to alleviate unhedgeable congestion that no market participant has proposed to resolve. … When the cumulative monthly unhedgeable congestion associated with a constraint exceeds the applicable market threshold, PJM posts a notice advising that it will begin an initial cost-benefit analysis of potential transmission enhancements that would relieve the applicable transmission constraint. PJM then opens a one-year 'market window' to solicit merchant solutions. Market-based proposals solicited during the market window may take many forms including generation, transmission or demand-side response solutions. A market-

[203] North American Electric Reliability Council, Transmission Loading Relieve Logs, January 15, 2006.

> based solution differs from a traditional utility solution because it may be proposed by an entity other than the regulated transmission owner. If no market-based solution is proposed within one year from the date of publication of the results of the initial cost-benefit analysis, PJM will include in the 'PJM Regional Transmission Expansion Plan' the transmission enhancement that is the most cost-effective, feasible solution."[204]

PJM nonetheless admits that the process for building economic upgrades is still incomplete.

> "PJM's RTEPP includes an economic planning component that is still under development."[205]

More importantly, PJM also admits that the process for building economic upgrades has simply not worked.

> "…our economic planning process has not been successful to date with respect to stimulating independent development of transmission projects. Only five transmission projects have been submitted into the interconnection queue as a direct result of the economic planning process and each represents minimal facility upgrades. In short, while the economic planning process is sending out useful information to developers, the revenue streams and the related level of certainty available through the interconnection process do not appear, at least so far, to be sufficient to promote the development of independent transmission projects. No significant projects have been proposed through the process to date."[206]

One of the impediments to transmission investment is the arbitrary distinction made in some RTOs between "reliability upgrades" and "economic upgrades." Reliability-based investments always allow reductions in generation redispatch costs that also would be expected to reduce market-clearing prices; and economic-based investments always provide reliability benefits. The distinction is made in the continuing hope that the market will build economic upgrades, but experience throughout the world indicates that this is more a hope than a reality. The unfortunate result of trying to distinguish between "reliability upgrades" and "economic upgrades" is that the distinction has permitted continued under-building of transmission facilities that planning processes clearly indicate would provide net benefits to wholesale customers and retail consumers.

PJM understands that its transmission planning process needs substantial reform if it is going to lead to the actual building of economic upgrades. A member of PJM's senior management has proposed the following:

> "PJM is exploring a consortium-like model with our transmission owners… We are approaching a replacement plan for aging transformers as if they were owned and operated by a single company. We are looking to apply a single set of criteria

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[204] PJM SOM Report 2004, pp. 239-240.

[205] PJM SOM Report 2004, p. 239.

[206] *Remarks of Audrey Zibelman, Executive Vice President PJM Interconnection, LLC*, Docket Nos. AD05-5-000 and PL03-1-000, April 21, 2005, p. 5.

> for determining which transformers need to be replaced across the whole market rather than continuing to have each transmission owner address the issue only as to their system. By applying this approach, we can prioritize transformer replacement based on their overall system impacts rather than simply by its impact within a single zone."[207]

PJM is considering the consortium approach because it has ruled out divestiture of existing transmission as well as consolidation of new transmission investment into a single entity.[208] It views the consortium approach as a way of "creating a 'virtual ITC' for infrastructure issues while still respecting individual asset ownership."[209] PJM recognizes that the fundamental issue is whether or not RTOs are going to have weak or strong transmission systems.

> "…should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its design, links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose?"[210]

4.2.2. Investment Trends

Five major transmission projects at the 345 kV level or above were completed in PJM, totaling 6.4 miles.[211] Three of the new projects were completed by AEP in the ECAR region.

Since its first plan was approved in 2000, PJM has authorized nearly $2 billion of transmission upgrades, $0.5 billion of which already have been completed by the 2005. According to PJM, the authorizations include $1.3 billion in "reliability" system upgrades and $0.5 billion in upgrades to interconnect new generation. The generation-related upgrades consist of more than 130 completed projects adding up to 17,021 MW of generation newly interconnected to the PJM grid plus an additional 3,897 MW of new generation currently under construction.

The total cost of the baseline reinforcements to the PJM system projected in the RTEP 2005 is $863 million, an increase of $192 million or 28.6% over the budget that appeared in the previous RTEP 2005 approved in early 2005.[212] Network upgrades to accommodate generation interconnection and merchant transmission investment projects are projected to cost $551 million, an increase of $105 million or 23.5% over the earlier approved amount in the RTEP 2005. The vast majority of the network upgrade costs, $533 million or 96.7%, are for generation

[207] *Ibid.*, p. 7.

[208] *Ibid.*

[209] *Ibid.*, p. 8.

[210] *Ibid.*, p. 5.

[211] NERC ES&D Database 2004. Updates from NERC as of April 19, 2005. Data are for new transmission-lines 230 kV and above, unless otherwise indicated.

[212] See Table 30 below.

interconnection.[213] Table 30 provides an overview of the major projects included in the updated RTEP 2005.

Table 30
Major Planned Baseline Transmission Reinforcement Projects in RTEP 2005[214]

PJM Zone	Project Description	Estimated Cost (Millions)
PSE&G Zone	Upgrade 138 kV circuit to 230 kV Substation transformer	$ 20 $ 6
JCP&L Zone	Capacitor	$ 1
PECO Zone	Capacitor installation	$ 8
AE Zone	Substations and transformer Reconductor 138 kV circuit Capacitor installation	$ 46 $ 6 $ 3
Eastern MAAC Region	Elimination of 1000 MVAR capacitor requirement in 2008	($ 20)
PEPCO Zone	Install two 230 kV circuits	$ 70
AP Zone	Install 450 MVAR SVC Install 500/345 kV transformer	$ 27 $ 12
Met-Ed Zone	Install reactor and capacitors	$ 13
Total		$192

Merchant transmission investment currently plays a small role in the upgrading and expansion of the PJM transmission grid. According to the RTEP 2005, 11 merchant projects are under consideration between the Mid-Atlantic and the Western Regions. Only one project is in service as of 2005 and one under construction as shown in Table 28. The remaining nine projects are all at the feasibility study stage or facility study stage.

Transmission investment in PJM is divided into two categories, "reliability upgrades" and "economic upgrades." "Reliability upgrades" are those investments that PJM has identified as necessary to assure reliable power system operation. Those projects appear in the baseline projects that are listed in Table 30 above. "Economic upgrades," by contrast, are not necessary to assure reliable power system operation but instead provide benefits in the form of reduced power system costs, particularly reduced generation redispatch costs. PJM identifies potential "economic upgrade" facilities and then seeks merchant transmission investor bids to build these facilities. Each identified project is offered in an "open market window"—a period of one year—in which interested parties can bid on the project. As of October 2005, 39 market windows (i.e., projects) have been closed without a bid. According to PJM's analysis, 28 of these projects, had they become merchant projects, would have substantially or entirely mitigated the congestion associated with one or more elements of the PJM grid.[215] The remaining 11

[213] Information on the RTEP 2005 update obtained from *PJM Regional Transmission Expansion Plan*, September 2005.

[214] Source: PJM RTEP 2005, September 2005, for the 2009 Baseline projections, p. 11.

[215] *Ibid*., p. 12.

"economic upgrade" projects, which are listed in Table 31, represent what so far has resulted from the merchant bids obtained through the RTEP process.

Table 31
Merchant "Economic" Transmission Projects Listed in the RTEP 2005[216]

Project Name	MW	Status	Schedule	Transmission Owner
Chichester-Linwood 230 kV		In-Service	2Q 2005	PECO
Black-Oak-Bedington		Feasibility Study Complete	4Q 2005	AP
Ft. Martin Prunytown		Impact Study Complete	1Q 2006	AP
Cheswick – Springdale 138 kV		Feasibility Study in Progress	2Q 2006	DQE
Grassy Falls	138	Feasibility Study in Progress	3Q 2006	AP
Linden 230 kV	300	Facility Study Complete	2Q 2007	PSEG
Sayreville 230 kV	790	Under Construction	2Q 2007	JCPL
Linden-HarborCable II	520	Feasibility Study In Progress	1Q 2008	PSEG
Bergen 230 kV	670	Feasibility Study In Progress	3Q 2009	PSEG
Black Oak – Bedington RTU		Feasibility Study in Progress	TBD	AP
Black-Oak- Hatfield Wave Trap		Feasibility Study in Progress	TBD	AP

4.2.3. Congestion

When congestion occurs in an LMP-based system such as that of PJM, the prices of energy in import-constrained areas are higher than elsewhere. LMPs reflect the price of the lowest-cost resources available to meet loads at each location, taking into account actual delivery constraints imposed by the transmission system. Differences between LMPs outside and inside of import-constrained areas determine the congestion costs of delivering power to import-constrained areas. In addition, congestion on transmission lines linking adjacent RTOs requires reciprocal agreements on how to manage such congestion, which in turn, creates issues of how to allocate the costs of inter-RTO congestion management efforts.

4.2.3.1. Congestion Costs

Table 32 presents congestion cost statistics. The overall trend in absolute congestion costs has been upward in PJM since the inception of the LMP-based energy market. Congestion costs per MWh of transactions have also been increasing substantially over time. These costs have ranged from 6% to 9% of PJM annual total billings since 2000, rising from 7% of total billings in calendar year 2003 to 9% of total billings in calendar years 2004 and 2005.

Total congestion costs were $808 million in calendar year 2004, a 62% increase from $499 million in calendar year 2003. The increase in congestion costs from 2004 to 2005 was 166%. Much of the increase can be attributed to the expansion of PJM, which resulted in the internalization of congestion on pathways among the AEP, ComEd, DAY, and Dominion control areas and between those zones and PJM Eastern division and significant shifts in congestion on pathways in the Eastern division of PJM. In particular, the completion in 2005 of the integration

[216] *Ibid*., p. 22 and p. 28.

of the six new control areas meant that, for the first time in 2004 and continuing through 2005, the significant congestion on the "Pathway" between ComEd and the Mid-Atlantic Region was suddenly counted as congestion for PJM. The Pathway was congested before the integration occurred; and the available statistics do not indicate how the integration affected the congestion on the Pathway. The most relevant cost comparison would be between congestion costs over the combined PJM-ComEd-AEP systems in 2003 (including Pathway congestion costs) versus congestion costs over that same combined system in 2004 and 2005. The available figures instead compare the PJM system in 2003 with the combined PJM-ComEd-AEP systems in 2004 and PJM-ComEd-AEP-DAY-DOM systems in 2005, which is not the correct basis for comparison.

Table 32
PJM RTO Congestion Costs 1999 – 2005[217]

Year	Congestion Cost (million $)	Percent Increase	Per-Unit Congestion Cost ($/MWh)	PJM Billings (millions $)	Congestion Cost Relative to PJM Billings
1999	53		0.20		
2000	132	149%	0.50	2,300	6%
2001	271	105%	1.02	3,400	8%
2002	430	59%	1.37	4,700	9%
2003	499	16%	1.52	6,900	7%
2004	808	62%	1.84	8,700	9%
2005	2,146	166%	3.13	22,630	9%

A true picture might instead show that congestion generally fell or did not rise significantly when adjusted for the expansion. This possibility is supported by Table 33, which presents year-to-year comparisons of numbers of constrained hours, constrained facilities, congestion-event hours, and so forth. The increases in several of these statistics are arguably due to the expansion, not to any actual increase in congestion or congestion costs; but there are nonetheless several statistics that show year-to-year decreases.[218] It is therefore not clear whether the integration has thus far resulted in any significant change in congestion.

Variations in monthly congestion costs have been substantial.[219] These variations are driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

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[217] This table is largely a replication of the PJM 2005 SOM Report's Table 7-1, p. 293. The calculated per-unit congestion cost also relies on PJM 2005 SOM Report, Table 2-33, p. 102.

[218] Several figures are missing from the 2003 and 2004 columns because the PJM 2004 SOM Report provides *changes* in some variables without providing the absolute levels of those variables.

[219] PJM 2004 SOM Report, Table 6-2, p. 206 and PJM 2005 SOM Report, Table 7-5, p. 297.

Table 34 shows congestion costs by planning period.[220] The table shows that FTR owners received 98% of the nominal values of their FTRs in the 2003 – 2004 planning period, and 100% in the 2004 – 2005 planning period. Through December 2005, FTR owners have received only 91% of nominal FTR values in the 2005 – 2006 planning period.

Table 33
Selected PJM Congestion Statistics

				Changes	
Variable	**2003**	**2004**	**2005**	**03-04**	**04-05**
Number of constrained hours[221]	5,104	5,742	7,138	12.5%	24.3%
Number of constrained facilities[222]	174	185	306	6.3%	65.4%
Number of congestion-event hours[223]	9,711	11,205	17,524	15.4%	56.4%
Number of hours with transformer constraints[224]	2,847	2,598	5,615	–8.7%	116.1%
Number of hours with interface constraints[225]	1,274	1,018	1,463	–20.1%	43.7%
Number of hours with transmission line constraints[226]	5,590	4,622	10,230	–17.3%	121.3%
Number of hours with 230 kV facility constraints[227]	3,016	2,340	2,537	–22.4%	8.4%
Number of hours with 115 kV facility constraints[228]				–484	
Number of hours with 500 kV facility constraints[229]	1,985	1,809	5,494	–8.9%	203.7%
Total congestion costs[230] (millions of $)	$499	$750	$2,090	50.3%	178.7%
Total congestion costs (as % of PJM billings)	7.2%	8.6%	9.2%		

[220] The planning periods run from July of one year to June of the following year.

[221] PJM 2004 SOM Report, p. 296 and PJM 2005 SOM Report, p. 398.

[222] PJM 2004 SOM Report, p. 209 and PJM 2005 SOM Report, p. 299.

[223] PJM 2004 SOM Report, p. 209 and PJM 2005 SOM Report, p. 299. The 2004 figure includes 2,512 congestion-event hours associated with the Phase 2 transmission "Pathway" between PJM and the ComEd Control Area before the integration of the American Electric Power (AEP) and Dayton Power & Light (DAY) Control Zones.

[224] PJM 2004 SOM Report, p. 213 and PJM 2005 SOM Report, p. 301.

[225] PJM 2004 SOM Report, p. 214 and PJM 2005 SOM Report, p. 301.

[226] PJM 2004 SOM Report, p. 214 and PJM 2005 SOM Report, p. 301.

[227] PJM 2004 SOM Report, p. 214 and PJM 2005 SOM Report, p. 303.

[228] PJM 2004 SOM Report, p. 214.

[229] PJM 2004 SOM Report, p. 215 and PJM 2005 SOM Report, p. 303.

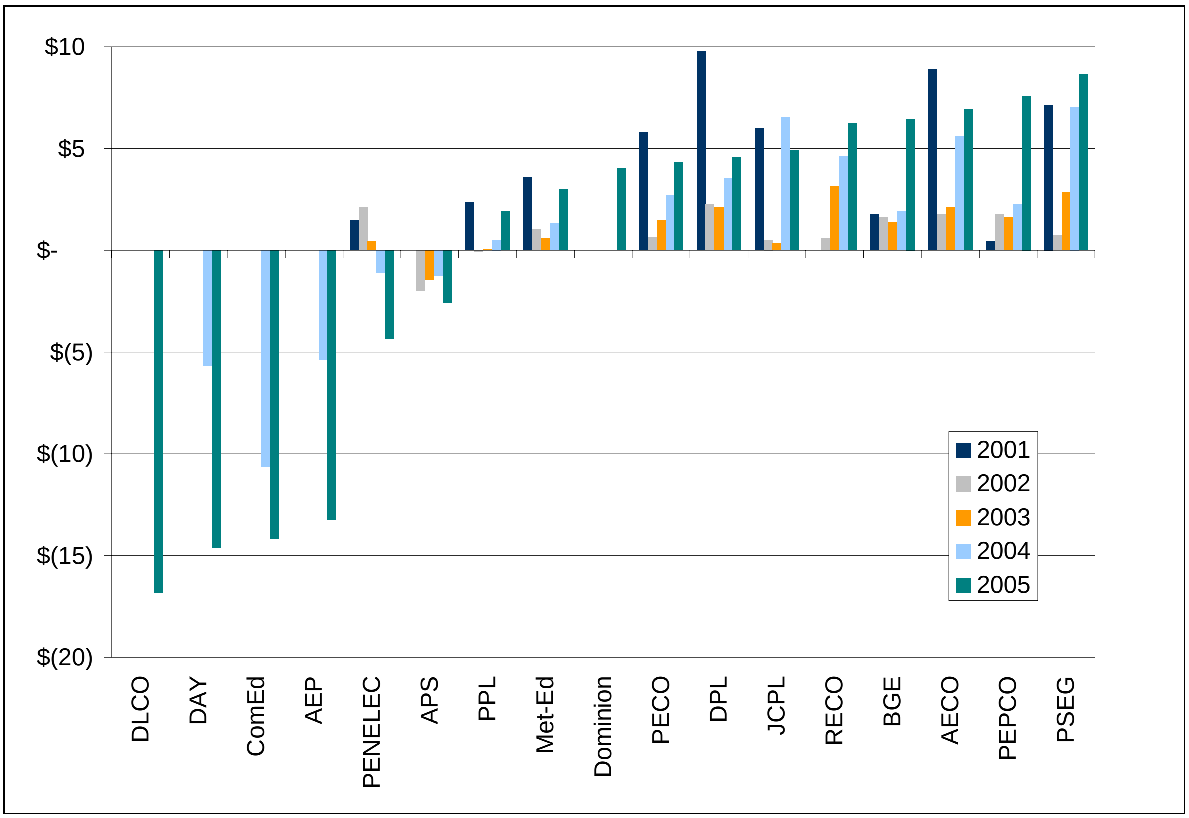
[230] PJM 2004 SOM Report, p. 37 and PJM 2005 SOM Report, p. 45.

Table 34
Congestion Costs by Planning Period[231]

Planning Period	Congestion Charges	FTR Target Allocations	Congestion Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
03-04 Final	$ 680	$ 696	$ 680	98%	$ 16	$ 0
04-05 Final	$1,118	$1,028	$1,028	100%	$ 0	$91
05-06 Partial	$1,672	$1,847	$1,672	91%	$175	$ 0

To provide an approximate indication of the geographic dispersion of congestion costs, average LMP differentials with the Western Hub price were calculated for control zones in the PJM Mid-Atlantic and Western Regions for the period 2001 to 2004. These are shown graphically in Figure 35. In comparison to congestion pattern in the years 2001 to 2003, the data show some changes in the overall congestion patterns during calendar year 2004, in particular for the Classic PJM companies PSEG, JCPL, and AECO.

Figure 35
Annual Average LMP Western Hub Price Differentials, 2001 – 2005[232]



[231] PJM 2005 SOM Report, Table 7-5, p. 297.

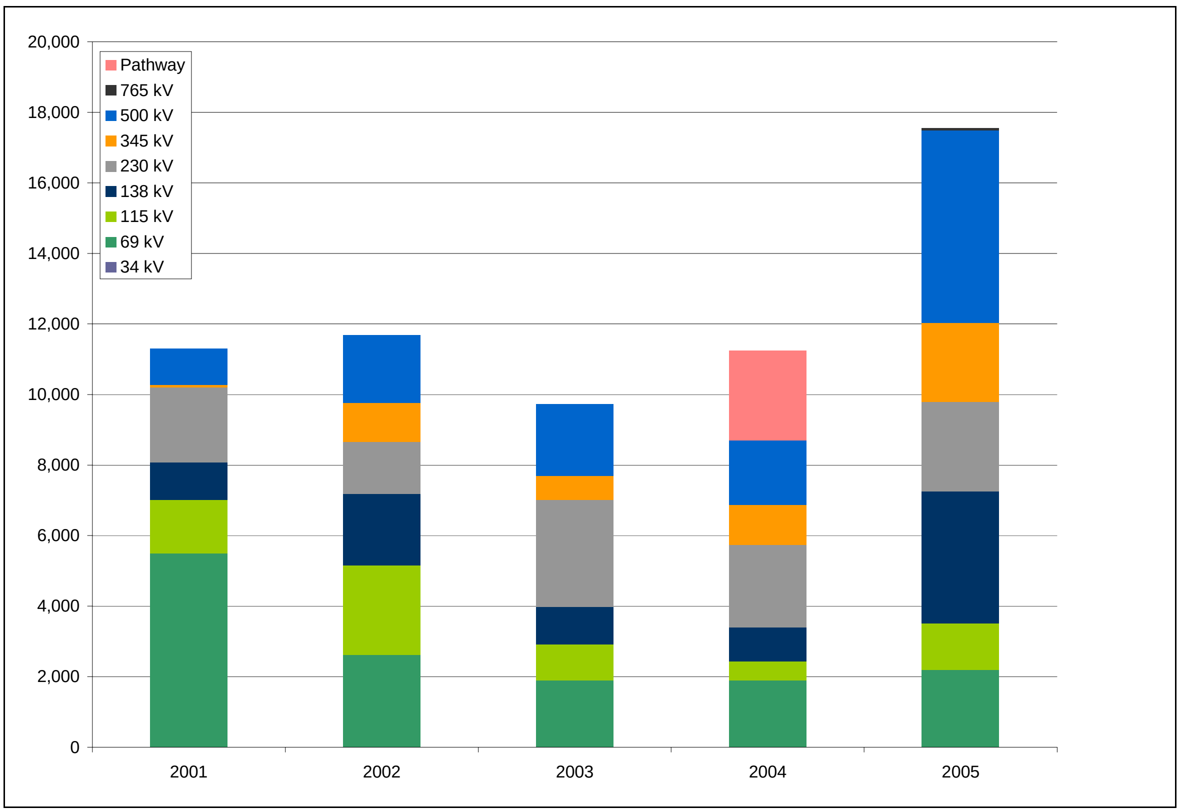
[232] PJM 2004 SOM Report, Figure 6-1, p. 208, and PJM 2005 SOM Report, Figure 7-1, p. 299.

4.2.3.2. Congestion Frequency

Figure 36 shows how congestion frequency has changed over the past five years. Congestion frequency increased in from 9,711 congestion-event hours during 2003 to 11,205 congestion-event hours in 2004 to 17,524 congestion-event hours in 2005. This is arguably due to the expansion in PJM's footprint. Because the increase from 2003 to 2004 included 2,512 congestion-event hours associated with the Pathway, the increase to 2004 was clearly due to solely to the expansion. Excluding Pathway congestion, there were overall decreases in congested hours experienced on interfaces, transformers, and lines during 2004 as compared to 2003.

Figure 37 shows the congestion hours by zone.

Figure 36
PJM Congestion Event-Hours by Facility Voltage: 2001 – 2005[233]



[233] PJM 2004 SOM Report, Figure 6-5, p. 215, and PJM 2005 SOM Report, Figure 7-4, p. 303. The vertical axis has units in "event-hours," that is, the number of hours in which there was congestion on transmission facility A plus the number of hours in which there was congestion on transmission facility, B.

Figure 37
PJM Congestion-Event Hours by Zone: 2001 – 2005[234]

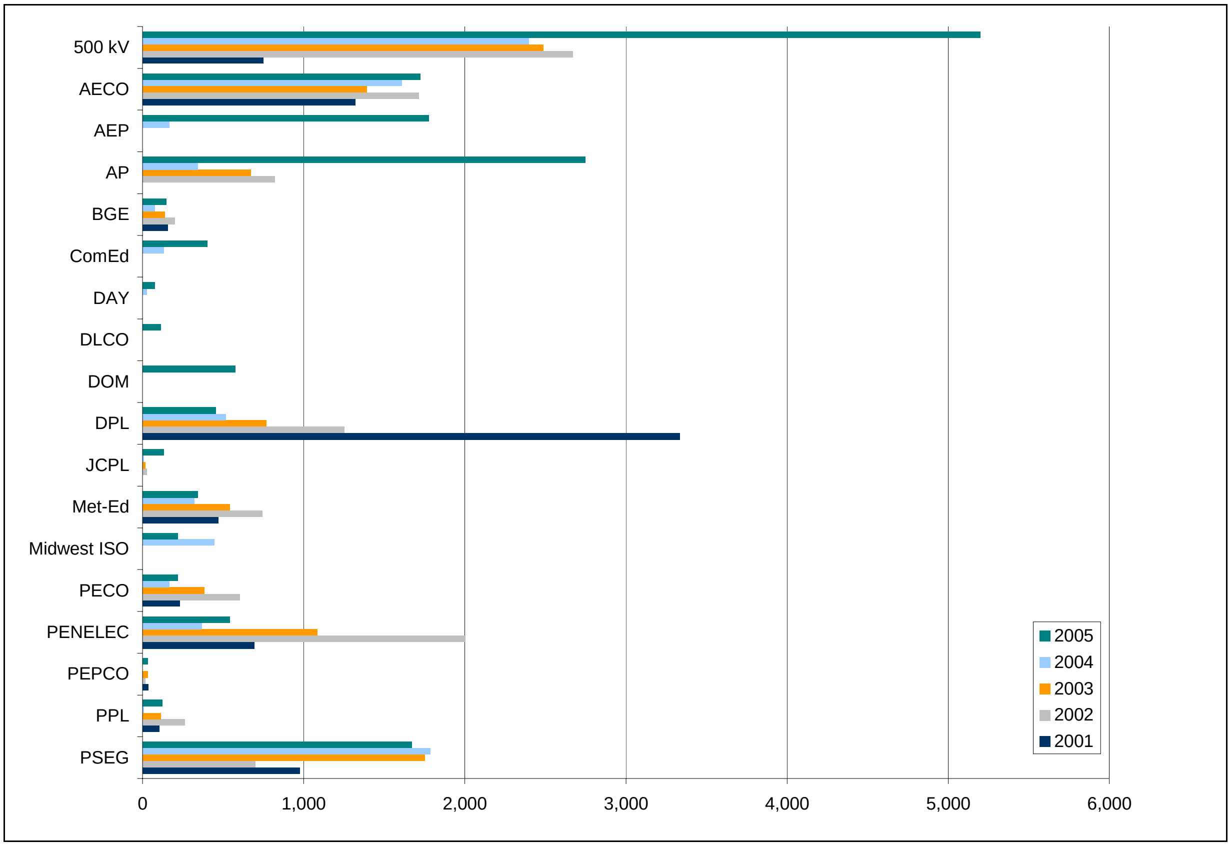


Figure 34 presented earlier shows that the TLR calls made by PJM since 1998 have been relatively small in number compared to some other regions of the country, but they have grown substantially over the past three years from 4,336 MWh to 6,324 MWh in 2005 (through November).[235] While the number of hours associated with PJM's level 5 TLR calls has more than doubled over the past three years, no transactions have been curtailed according to the NERC TLR logs. The TLR calls occur on the flowgates linking the PJM system to adjacent systems.

4.2.4. Transmission Rights

In PJM, transmission rights are financial and go by the names of Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs).

This section begins with a discussion of the design of transmission rights within PJM, then considers market structure, and finally looks at the relationship between the actual value of transmission rights and their nominal value.

[234] PJM 2004 SOM Report, Figure 6-8, p. 219, and PJM 2005 SOM Report, Figure 7-7, p. 308.

[235] NERC TLR Logs 2003 to 2005 (November) obtained at http://www.nerc.com/~filez/Logs/tlrlogs.html .

4.2.4.1. *Market Design*

A transmission right can be thought of as a right to delivery of a specified MW quantity of power from a source (generation) location to a sink (load) location. In PJM, a Financial Transmission Right (FTR) provides its owner with "congestion revenues" equal the MW quantity of the FTR times the difference in the day-ahead LMP prices at the source and sink locations that define the FTR. Transmission customers who own FTRs thus have a hedge against congestion costs between the source and sink locations of their FTRs: if they have generation and load at those locations, the congestion costs that they pay for power transmission will be offset by the congestion revenues that they receive through their FTRs.

Transmission customers may acquire FTRs either through PJM-administered auctions or bilateral trades. In the auctions, the winning bids are those that have requested transmission service that can be simultaneously accommodated by the transmission system (the so-called "simultaneous feasibility test") and that has the highest total as-bid value of any combination of bids. The auction proceeds go to the owners of *Auction Revenue Rights* (ARRs).

ARRs provide their owners with the proceeds received from FTR auctions. Market participants can acquire ARRs either by financing transmission upgrades or through entitlement. Participants who finance upgrades must pay for both the upfront capital expense and the on-going operation and maintenance expenses of the upgrade. These ARRs are in force for the life of the upgrade, up to thirty years. Participants receive ARRs through entitlement if they are Network Service Customers and Firm Point-to-Point Service Customers. Network customers receive ARRs for each zone according to their shares of total peak load in each zone. Point-to-point customers receive ARRs according to the sizes of their transmission reservations. Entitlements thus follow load, so as load shifts among LSEs, proportionate shares of ARRs move with the load.

As a practical matter, the owner of an ARR can convert their ARRs into the corresponding FTRs. Consequently, ARR owners can hedge themselves against congestion at essentially no cost if their ARRs match the FTRs that they would want.

Monthly FTRs have been available to Network Service Customers and Firm Point-to-Point Service Customers since the inception of locational energy pricing on April 1, 1998. ARRs were introduced on June 1, 2003, at which time PJM introduced an annual FTR auction. ARRs have been available in the Mid-Atlantic Region and the AP and ComEd Control Zones since 2004. They are presently being phased into the AEP and DAY Control Zones.

PJM also runs monthly auctions designed to permit bilateral FTR sales and to allow eligible participants to buy any residual system FTRs. For the 2003 to 2004 planning period, PJM introduced 24-hour FTRs into the monthly auctions. At the same time, PJM also added annual and monthly FTR options. Unlike standard FTRs, the options can never be a financial liability.

PJM does not have a market for transmission rights longer than one year in duration. Its proposed Reliability Pricing Model market would, however, create transmission rights four years into the future. The longer-term transmission rights are important for encouraging new generation investments.

4.2.4.2. *ARR Sufficiency*

"ARR sufficiency" refers to the relationship between: a) the value of transmission rights that are available to market participants, as measured by the auction values of FTRs; and b) the aggregate values of the ARRs that market participants want. In general, the transmission rights that are available will be less—often substantially less—than the transmission rights that market participants want.

The basic story is that the available transmission rights cover only a portion of transmission customers' needs. Table 35 shows the quantities of ARRs that were requested and available in the two most recent planning years. These figures suggest that transmission rights were available to cover only 61% and 72% of market participants' requests in the 2004 – 2005 and 2005 – 2006 planning years, respectively. However, these percentages are calculated in terms of MWs rather than values, they are estimates of (rather than the final word on) ARR adequacy.

Table 35
PJM ARR Sufficiency[236]

Planning Year	Requests (MW)	Supply (MW)	Sufficiency
2004-2005	55,128	33,589	61%
2005-2006	82,343	59,410	72%

ARR sufficiency varies widely by regions within PJM. The main insufficiencies are in the PEPCO, PSEG, PECO, JCPL, and AECO Control Zones.[237] At the other extreme, load in the ComEd, AP, PENELEC, and PPL transmission zones was fully hedged by the ARRs.

ARR holders received credits valued at $311 million during the 2003 – 2004 planning period, with an average hourly ARR credit of $1.23 per MWh. ARR holders will receive credits valued at $345 million during the 2004 – 2005 planning period, with an average hourly ARR credit of $1.17 per MWh. ARRs by definition are 100% revenue adequate.

4.2.4.3. *FTR Revenue Adequacy*

"Revenue adequacy" refers to the relationship between: a) the aggregate congestion charges that are paid by transmission customers in day-ahead energy markets; and b) the aggregate nominal values of outstanding FTRs, which are the promised payments to FTR owners. Revenues are adequate if congestion charges are sufficient to fully pay the promised amounts to FTR owners; and there are revenue shortfalls when congestion charges are not so sufficient.

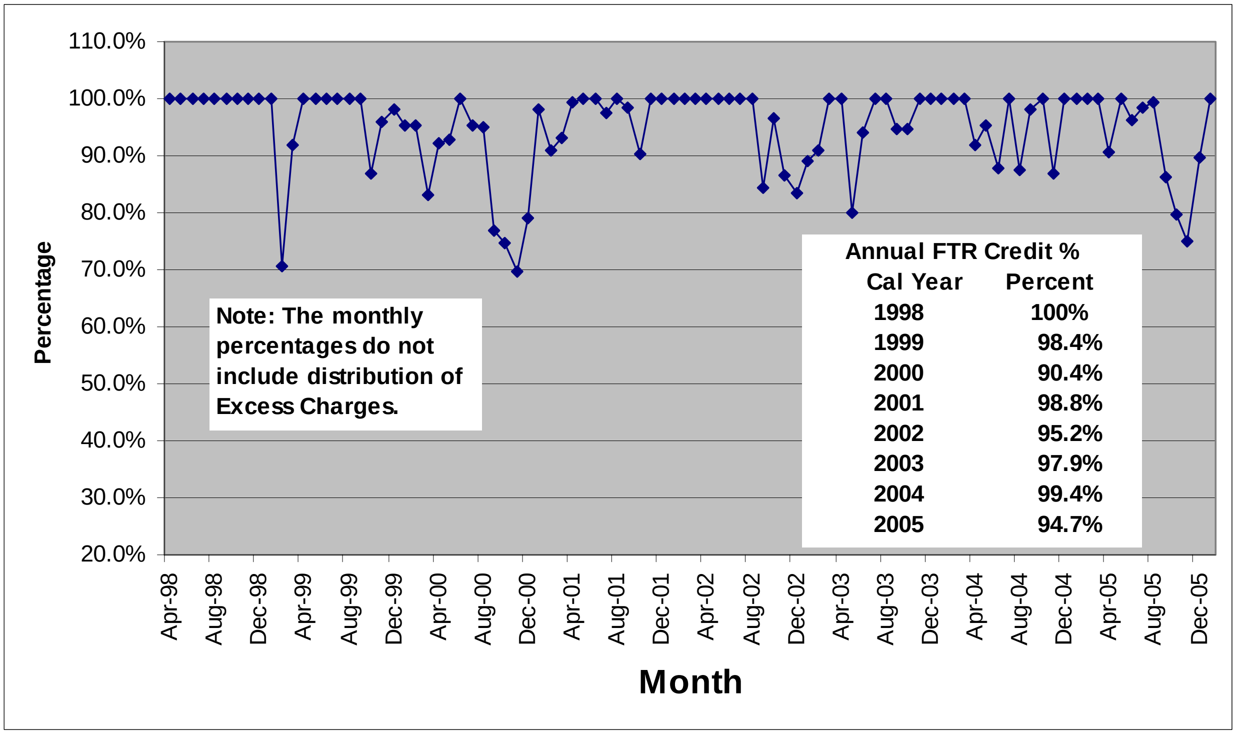
Revenue adequacy is measured as the ratio of congestion charges to promised payments. Figure 35 shows the monthly values of this ratio since August 1998 to January 2006. In many months, revenues have been fully adequate: congestion charges have equaled 100% of promised amounts. There have been some months, however, in which the ratio has fallen as low as 70%. This is not

[236] PJM 2004 SOM Report, p. 247.

[237] PJM 2004 SOM Report, p. 247 and p. 254, and PJM 2005 SOM Report, p. 49.

as adverse as it may seem, however, because congestion charge surpluses in some months are used to offset congestion charge deficiencies in other months. As shown in Figure 38, the annual ratio has never fallen below 90%, and has generally been above 95%.

Figure 38
Percent FTR Credit by Month: April 1998 to January 2006



A summary of ARR and FTR values and revenue adequacy is presented in Table 36. Annual and Monthly FTR auction revenue is allocated to ARR holders based on ARR target allocations. PJM collected $358 million in FTR auction revenue during the 2003 – 2004 planning period and collected $385 million during the 2004 – 2005 planning period, exceeding the FTR target allocation by $40 million for the latter planning period. Thus, ARRs were 100% revenue adequate for each of the past two planning periods. For the 2005 – 2006 planning period, PJM collected $892 million through the end of 2005 that exceeded the ARR target allocations of $870 million, making ARRs 100% revenue adequate for the first seven months of the 2005 – 2006 planning period.

Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $680 million of congestion revenues during the 2003-2004 planning period, $1,118 million during the 2004 – 2005 planning period, and $1,672 million through the first seven months of the 2005 – 2006 planning period (i.e., through December 2005). FTRs were 98% revenue adequate during the 2003 – 2004 planning period and 100% revenue adequate for the 2004-2005 planning period. FTRs through December 31, 2005, of the planning period ending May 31, 2006, have been paid at 91% of the target allocation level. For the calendar year 2005, FTRs were 95% revenue adequate.

Table 36
PJM ARR and FTR Values and Adequacy by Planning Period, 2003 – 2006[238]

Planning Period Year	FTR Auction Revenue (mm $)	ARR Credit Value (mm $)	ARR Average Hourly Credit Value ($/MWh)	FTR Target Revenue (mm $)	Congestion Revenue (mm $)	Revenue Adequacy Percentage
6/03-5/04	359	311	1.23	694	680	98%
6/04-5/05	385	345	1.17	646	1,118	100%
6/05-5/06[239]	892	870	NA	NA	1,672	91%

FTRs are also insufficient in PJM. For the 2005 to 2006 planning period, in the Annual Auction Market, total FTR Auction demand was 871,841 MW, up 1.2% from the 2004 to 2005 planning period. The Auction Market cleared 141,179 MW (16.2% of demand), leaving 730,662 MW of uncleared bids. In the FTR Auction Market for the 2004 to 2005 planning period, the demand was 861,323 MW while the market cleared only 119,629 MW (13.9% of demand), leaving uncleared bids of 741,694 MW. Under the Annual FTR Auction, there is no limit on FTR demand. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs; numerous combinations of FTRs are feasible. The principal binding constraints limiting the supply of FTRs during the 2005 2006 planning period were the Jefferson 138 kV line, the Mahans Lane 138 kV line and the Branchburg 500/230 kV transformer.

4.2.4.4. FTR Market Performance

FTR market performance can be assessed partly according to price levels (e.g., are prices going down or up over time?); but since the purpose of FTRs is to hedge against day-ahead congestion costs, the real test is whether FTR prices reasonably reflect congestion cost outcomes. Consequently, we look here at FTR price trends and at FTR price biases relative to realized day-ahead congestion prices.

For customers wishing to purchase transmission rights, annual FTR prices have recently increased modestly for 24-hour FTRs and fallen for on-peak and off-peak FTRs. Meanwhile, monthly FTR prices have been falling. Summary statistics appear in Tables 37 and 38. Table 37 shows prices for annual FTRs. The first three data columns show prices for each planning year, and the two rightmost columns show the year-to-year percent price changes. Table 38 shows prices for monthly FTRs.

238 PJM 2005 SOM Report, p. 370.

239 Values are for the planning period through the end of calendar 2005.

Table 37
Annual FTR Obligation Prices by Type and Planning Period
($/MWh)[240]

	Price Levels			**Price Changes**	
	2003-2004	**2004-2005**	**2005-2006**	**03-04/04-05**	**04-05/05-06**
24-hour	$1.09	$1.27	$1.56	16.5%	22.8%
On-peak	$0.34	$0.16	$0.40	-47.1%	150%
Off-peak	$0.15	$0.13	$0.33	-13.3%	154%

Table 38
Average Monthly FTR Obligation Prices
($/MWh)[241]

Year	2001-2002	2003	2004	2005
Price	$0.49	$0.27	$0.09	$0.10

The MMU concludes that FTR Auction Market results were competitive in 2005.

4.3. Midwest ISO

4.3.1. Transmission Planning Process

The Midwest ISO's transmission planning process looks about five years into the future; so the most recent Midwest Transmission Expansion Plan (MTEP), issued in June 2005, looks at transmission needs through 2009. That MTEP has identified 615 Planned or Proposed projects with a capital cost of $2.91 billion through 2009. "Planned" projects are more firm than "Proposed" projects: "transmission owners are expected to make the investments necessary to implement the Planned Projects in this expansion plan…"[242]

Although the planned and proposed projects together assure reliability; "the Midwest ISO has not independently evaluated … whether these expansions are the most efficient solutions to reliability issues identified."[243] Furthermore, Planned and Proposed projects apparently include only those that are needed for reliability purposes, not those that allow substantial reductions in congestion and in generation costs. Midwest ISO intends to recommend congestion-reducing transmission plans "…at such time as the Midwest ISO in collaboration with interested stakeholders can complete these evaluations, and a determination of cost responsibility and recovery can be made…"[244] In summary, the Midwest ISO's transmission planning process

[240] PJM 2005 SOM Report, p. 349.

[241] PJM 2005 SOM Report, p. 350.

[242] 2005 MTEP, p. 3.

[243] 2005 MTEP, p. 1.

[244] 2005 MTEP, p. 14.

assures reliability, but does not necessarily provide least-cost transmission plans either for reliability in isolation or for reliability and congestion together.

Agreement has not yet been reached on the assignment of cost responsibility for transmission expansion. On the one hand, the present Midwest ISO tariff and Transmission Owners Agreement generally assign the costs of load-growth driven upgrades to the local Transmission Owner constructing the upgrade.[245] On the other hand, the Midwest ISO has proposed that the costs of Baseline Reliability Projects—which are projects rated at 100 kV or above that are needed to maintain system reliability—be allocated as follows:[246]

- For projects rated 345 kV and higher, 20% of costs would be allocated regionally through a system-wide rate, and remaining costs would be allocated on a subregional basis according to Line Outage Distribution Factors.
- For projects rated between 100 kV and 344 kV, all costs would be allocated on a subregional basis according to Line Outage Distribution Factors.

The costs of Baseline Reliability Projects would not be the responsibility of new transmission service or interconnection customers.[247] The Midwest ISO's proposal is pending at FERC. With regard to economic upgrades, the Midwest ISO will be submitting a proposal to FERC in late 2006.

4.3.2. Investment Trends

Figure 39 shows the planned and proposed transmission investments for each of the six years 2004-2009, according to the most recent MTEP. The figure shows sharp upward trends in planned, proposed, and total investments through 2008. After 2008, plans apparently become more uncertain, as most investments are merely proposed rather than planned, and the total volume of investments falls.

4.3.3. Congestion

Prior to the April 2005 introduction of LMP and the Day 2 Market, the Midwest ISO had significant problems with TLR calls and rejections of short-term reservation requests. The problems were so bad that, in 2004, Midwest ISO flowgates accounted for most of the TLR calls in the Eastern Interconnection, with the WUMS regions experiencing more TLRs than any other Midwest ISO region. Some of these congestion problems were due to the integration of Commonwealth Edison and American Electric Power into PJM, which increased transmission flows through northern Indiana.[248]

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[245] 2005 MTEP, p. 4.

[246] Joint Request 2/17/06, p. 3.

[247] 2005 MTEP, p. 8.

[248] 2004 SOM Report, p. vii.

Figure 39
Midwest ISO Region Planned and Proposed Transmission Investments, 2004 – 2009[249]

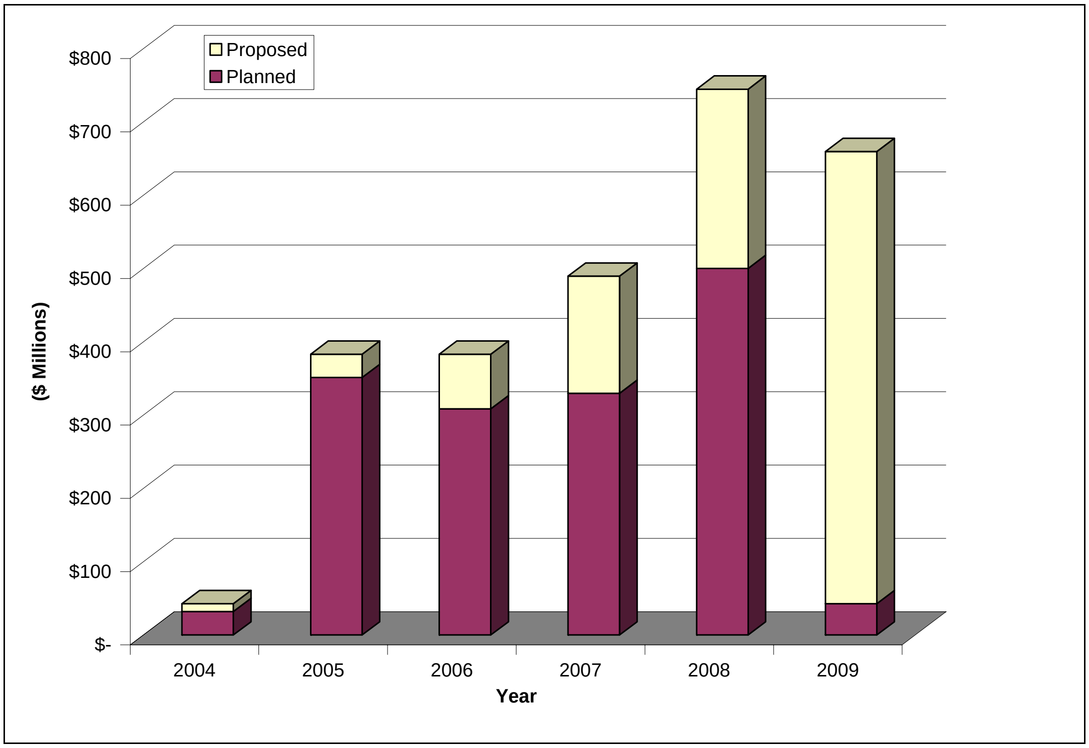


Figure 40 shows how the Midwest ISO's Day 2 Market has affected TLR calls. The bars show that the number of TLR calls is down only slightly in 2005 relative to 2004. On the other hand, the line shows that the GWh volume of TLR calls declined by 76% from 2004 to 2005. Because the cost of TLR calls is related to the GWh volumes, the Day 2 Market has apparently improved the efficiency of congestion management.

Figure 41 shows the bi-monthly GWh volumes of reservation requests accepted and refused during the years 2002 through 2004. It is striking that most requests were refused. "A significant factor in the high volume of refused requests is the denial of long-term [i.e., monthly and annual] firm service, which tends to account for a large volume of transmission service due to their duration.[250] Another significant factor is that, prior to introduction of the Day 2 Market, the prices for transmission services did not reflect the costs of transmission congestion and therefore failed to discourage use of congested facilities. Yet another significant factor is that "the process for obtaining long-term transmission service … creates incentives for participants … to submit numerous requests for service … even if the participant intends to confirm only one of the requests."[251]

[249] Based on 2005 MTEP, Figure 1.5-1, p. 15.

[250] 2004 SOM Report, p. 27.

[251] 2004 SOM Report, p. 30.

Figure 40
TLR Events and Curtailments[252]

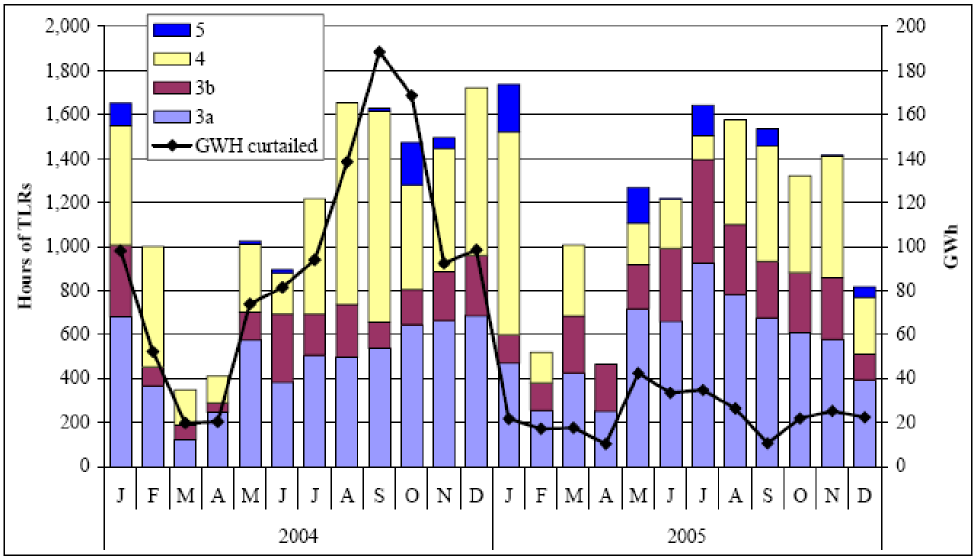
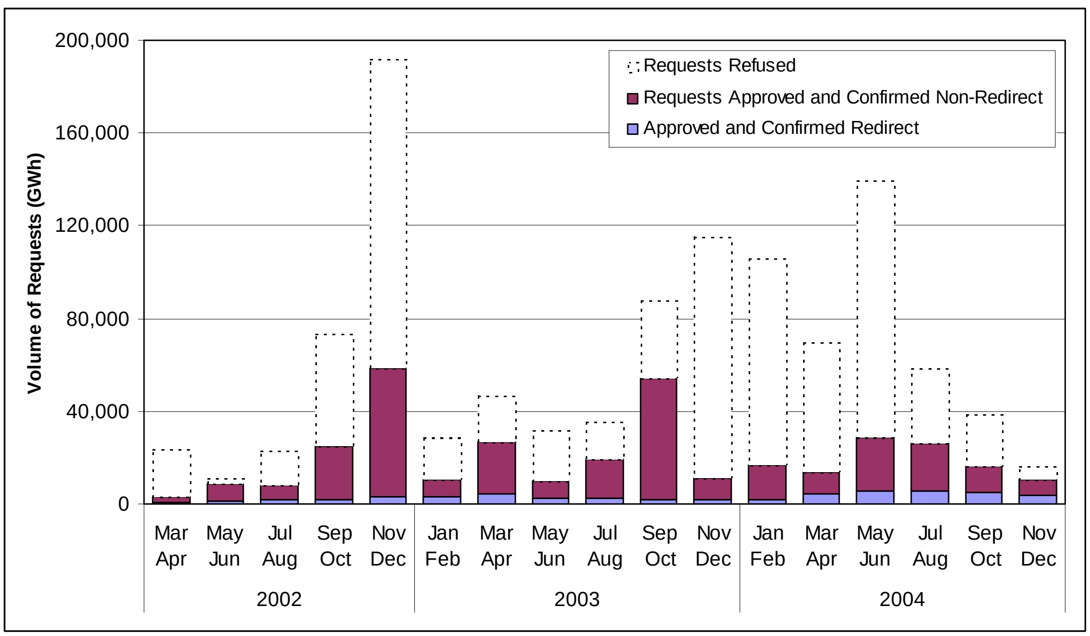


Figure 41
Midwest ISO Disposition of Reservation Requests (GWh), 2002 – 2004[253]



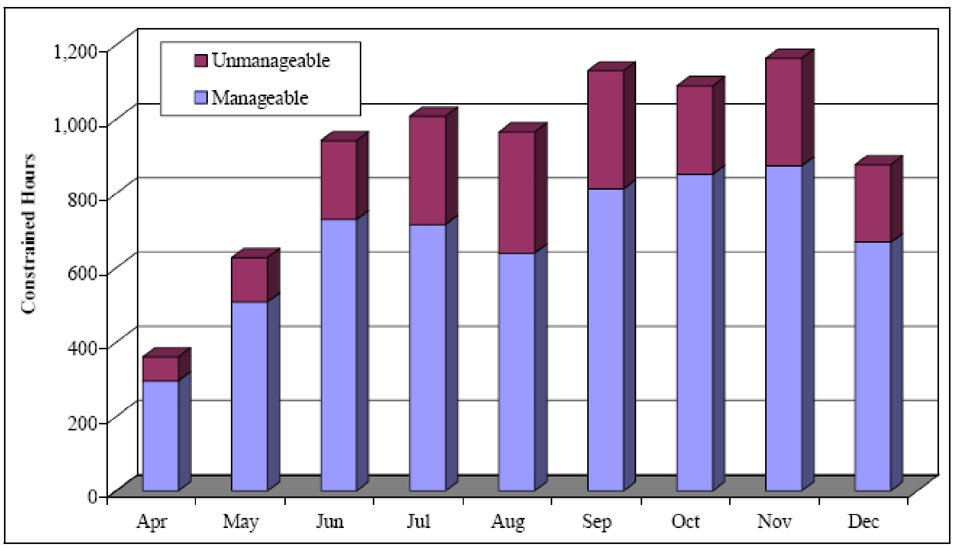
For interfaces that are internal to the Midwest ISO, the foregoing scheduling problems have been largely eliminated. Customers no longer need to request transmission service; they merely need to pay the current congestion charges. Furthermore, these charges should ration congested

[252] Midwest ISO 2005 SOM, Figure 42, p. 60.

[253] 2004 SOM Report, p. 27.

interfaces to the highest-valued uses. But while the Day 2 market has eliminated the scheduling problem, it has engendered a new breed of congestion management problem. In 2005, an astonishing 25% of Day 2's congestion was "unmanageable." Figure 42 shows a monthly breakdown of "manageable" and "unmanageable" hours. Midwest ISO defines a transmission constraint as "unmanageable" when "there is not sufficient redispatch capability in the market to reduce the flow to less than the limit in the next 5-minute interval…"[254] The IMM attributes this inability to manage transmission flows to two causes: generator inflexibility in offering redispatch capability; and a Midwest ISO modeling rule that limits Midwest ISO's ability to redispatch certain generators, even when those generator are willing to help manage transmission constraints.[255] The IMM asserts, however, that "The presence of an unmanageable constraint does not mean the system is unreliable—reliability standards require the flow to be less than the limit within 30 minutes."[256]

Figure 42
Midwest ISO Disposition of Reservation Requests (GWh), 2002 – 2004[257]



As a purely mathematical matter, when a constraint is unmanageable, LMPs cannot be meaningfully calculated. To produce LMPs under such circumstances, the Midwest ISO resorts to the mathematical technique of "relaxing" constraint limits. In essence, the Midwest ISO underprices congestion when a constraint is "unmanageable." The IMM has therefore recommended that "MISO discontinue use of the relaxation algorithm and set prices based on the

[254] Patton, Midwest ISO 2005 SOM, p. 113.

[255] Patton, Midwest ISO 2005 SOM, p. 11.

[256] Patton, Midwest ISO 2005 SOM, p. 113.

[257] Midwest ISO 2005 SOM, Figure 44, p. 63.

constraint penalty factor… To the extent that the relaxation algorithm determines a lower shadow price, therefore, it is a poorer reflection of the true value of the constraint."[258]

For interfaces that interconnect the Midwest ISO with adjacent areas, the scheduling problems continue. "For example, three of the top five interfaces with self-competing requests are for capability from the Midwest ISO area to IMO [Ontario]. The other two interfaces are from the Midwest ISO to PJM."[259] Furthermore, the Midwest ISO, being in the center of the continent, is subject to loop flows, particularly "by PJM exports to TVA that were not well coordinated with the Midwest ISO for most of the year."[260] "Non-firm transmission service sold by PJM to TVA loaded these [north-south] interfaces [through Midwest ISO]. This service was not initially coordinated under the market-to-market provisions. PJM has taken steps to limit this service when Midwest ISO has no ATC."[261]

4.3.3.1. Congestion Costs

Figure 43 shows the Midwest ISO congestion costs, by month, during the Day 2 market period of 2005. It shows that these costs were substantial, reaching a peak in the late summer and early fall. It implies that congestion costs in the real-time market were almost a third of the total congestion costs. According to the IMM, "one would expect the real-time congestion to be very low if the modeling of the transmission system is consistent in the day-ahead and real-time markets."[262] The large level of real-time congestion costs indicates significant day-ahead misforecasts of line limits, external loop flows, and other factors.[263]

Not surprisingly, "the highest value congestion was on the interfaces into the WUMS area…,"[264] which is the most transmission-constrained area of Midwest ISO.

4.3.3.2. Congestion Frequency

4.3.4. Transmission Rights

The Midwest ISO offers Financial Transmission Rights (FTRs) as a tool for hedging against uncertainties in the differences among the LMPs at resource and load locations. The Midwest ISO's FTRs were fully funded in 2005.[265]

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[258] Patton, Midwest ISO 2005 SOM, p. 122.

[259] 2004 SOM Report, pp. 31-32.

[260] Patton, Midwest ISO 2005 SOM, p. 12.

[261] Patton, Midwest ISO 2005 SOM, p. 115.

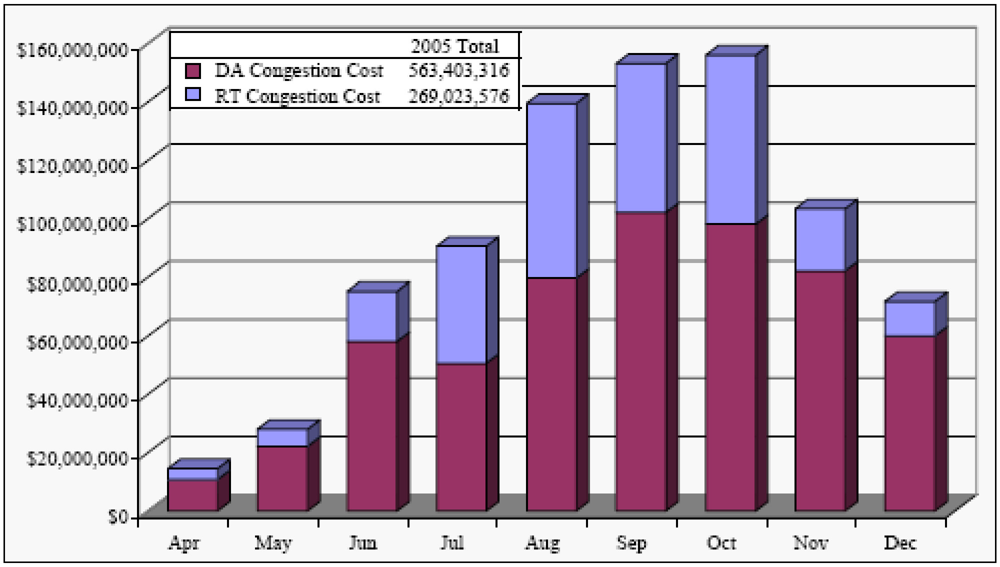
[262] Patton, Midwest ISO 2005 SOM, p. 98.

[263] Patton, Midwest ISO 2005 SOM, p. 124.

[264] Patton, Midwest ISO 2005 SOM, p. 115.

[265] Patton, Midwest ISO 2005 SOM, p. 13.

Figure 43
Total Midwest ISO Congestion Costs April to December 2005[266]



4.3.4.1. Market Design[267]

Market participants obtain FTRs in one of three ways.

First, participants who had transmission rights prior to the formation of the Midwest ISO have grandfathered rights (GFAs). The owners of transmission rights under GFAs are exempt from congestion charges, loss charges, and certain other charges, such as the Schedule 16 charges that recover the Midwest ISO's costs of administering FTR markets. In addition, the day-ahead schedules associated with GFAs are non-binding. On the other hand, these owners are responsible for Schedule 17 charges pertaining to the creation of energy markets as well as for the ISO's costs of maintaining reliability and managing real-time energy imbalances, including Revenue Sufficiency Guarantee costs.[268]

Second, participants can request that they be allocated FTRs. A participant's maximum candidate FTR (CFTR) request is determined by that participant's forecast Peak Network Load plus Grandfathered Service plus Firm Point-To-Point reservations.[269] In the allocation of FTRs, longer-term rights have priority over shorter-term rights; and, under some conditions, shorter-term FTRs are conditional and may be revoked to serve longer-term FTR requests.[270] The annual allocation of FTRs is performed separately for on-peak and off-peak periods for each of

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[266] Patton, Midwest ISO 2005 SOM, p. 99.

[267] See EMT, Sheet Nos. 614-677.

[268] Midwest ISO Answer 1/9/06, p. 2-4 and Spence 1/31/06, p. 2-3.

[269] EMT, Second Substitute Second Revised Sheet No. 614.

[270] FERC 8/6/04, pp. 58-59 and EMT, Second Revised Sheet No. 637.

four seasons of each year. New transmission customers are not entitled to the same level of FTRs as existing Transmission Customers.[271]

Third, participants can purchase seasonal on-peak and off-peak FTRs through the RTO's auctions. The transfer capability that is available through these auctions is the entire expected monthly transfer capability net of the FTRs that are grandfathered or allocated, as described above. In the auctions, the winning bids are those that have the maximum net economic value as measured by the bids, subject to a simultaneous feasibility test.[272] Purchasers of all comparable FTRs pay the same market-clearing price.

A market participant can request changes in the points of receipt or delivery for their FTRs. If a market participant elects not to exercise a transmission service rollover right, the corresponding FTRs are cancelled.[273]

The Midwest ISO is developing a plan for creating auction revenue rights (ARRs) that are similar to those of PJM. Such rights will entitle the holder to the revenues from FTR auctions.[274]

4.3.4.2. FTR Market Performance

One key measure of FTR market performance is the extent to which FTRs are fully funded. If transmission capabilities are different than the capabilities that were assumed when the FTRs were issued, the FTR owners may be paid congestion costs that are less than the nominal "obligation" value of their FTRs. Another key measure of FTR market performance is the difference between the auction prices for FTRs sold in monthly auctions and the congestion revenues actually paid to the auction winners. Over time, the FTR auction prices should be roughly equal to the actual congestion revenues.

Figure 44 looks at the first measure of FTR market performance. The figure shows the congestion cost funds that were available to pay FTR holders in each of the months of the Day 2 market in 2005. In the first six months, congestion cost funds were more than adequate to pay the nominal obligations, meaning that the transmission capabilities likely exceeded the capabilities that were forecast when the FTRs were issues; but in the last three months, there was a funding shortfall. That funding shortfall arose because of unexpected transmission outages and because of increasing loop flows (between PJM and TVA) during the last three months of 2005. For the year, however, funding was sufficient, so the FTR holders were 100% hedged with respect to the day-ahead congestion costs covered by their FTRs.

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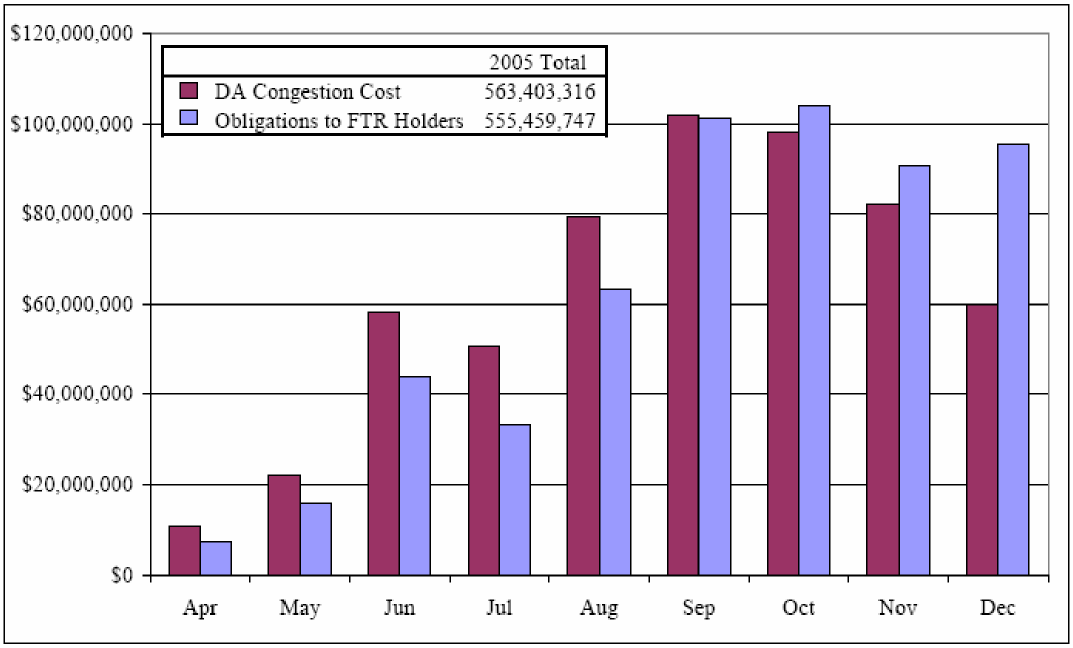
[271] EMT, Second Revised Sheet No. 648.

[272] The Midwest ISO's models for conducting simultaneous feasibility tests is problematic. According to Spence 12/15/05, p. 3, these models "may inject more power at a node than the generating plant can actually produce, which may cause artificial constraints and reduce the allocation of FTRs."

[273] Spence 12/15/05, p. 5.

[274] EMT, Second Revised Sheet Nos. 647 and 677.

Figure 44
Midwest ISO Day-Ahead Congestion and Payments to FTR Holders: 2005[275]



Another type of transmission right was created for the benefit of market participants whose pre-existing "grandfathered" contracts entitles them to use of the transmission system without payment of congestion charges. These rights, through a rebate mechanism, generally exempt their holders from paying congestion charges.[276]

Figure 45 shows the payments made by the Midwest ISO to all FTR holders.[277] When grandfathered transmission agreements are factored into the payments picture, the day-ahead congestion revenues received by the Midwest ISO were short in 2005 by $47.2 million.

The IMM has calculated the implied "value" of real-time congestion as the marginal cost of the constraint (i.e., the shadow price) times the flow over the constraint in a given dispatch interval, giving a value for 2005 of about $1.2 billion. This is substantially greater than the day-ahead market congestion revenues of $475 million. The difference is due primarily to power flows across the Midwest ISO's grid that are not required to pay congestion charges, of which approximately $400 million[278] is associated with market-to-market transmission (e.g., between PJM and TVA). The IMM and the Midwest ISO recognize the need for improvements in the

[275] Midwest ISO SOM 2005, Figure 38, p. 54.

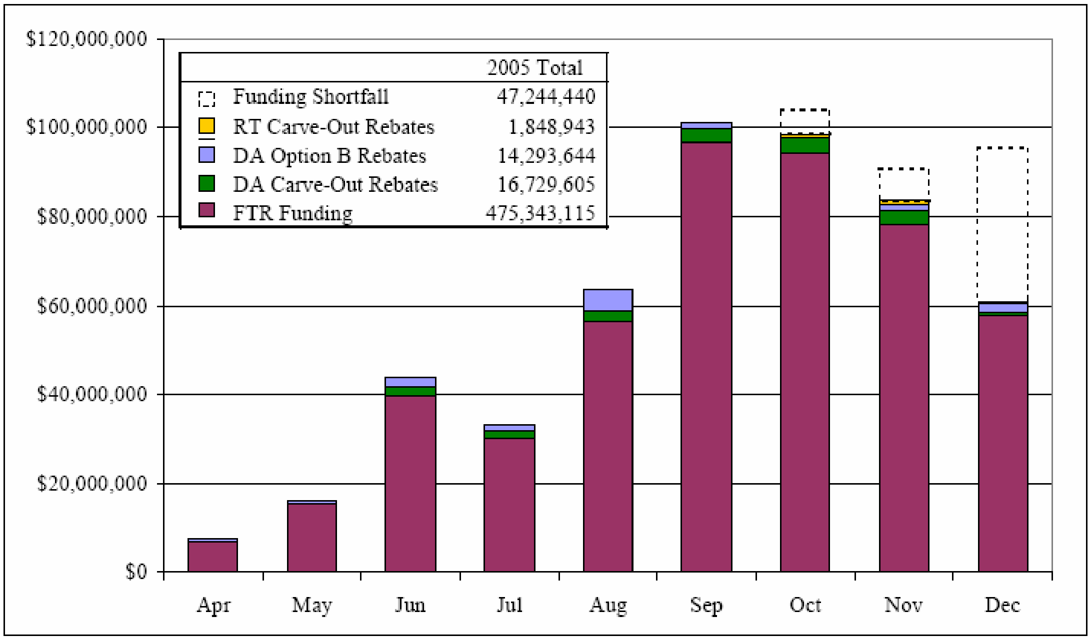
[276] The rights include an alternative type of FTR with use-it-or-lose-it characteristics (Option B FTRs) and congestion "carve-outs." Figure 45 shows the monthly payments and obligations to FTR holders, including payments to FTR Option B and Carve-Out FTRs.

[277] The bars in Figure 45, including shortfalls, are the same as the "Obligations to FTR Holders" bars in Figure 44.

[278] This estimate is based on subjective assessment of the amounts implied by Figure 41, p. 58 of the Midwest ISO SOM 2005.

coordination between markets (such as between PJM and the Midwest ISO) in both day-ahead and real-time markets.

Figure 45
Midwest ISO Payments to All FTR Holders for All Hours: 2005[279]



Turning to the second measure of FTR market performance, when the market for FTRs is efficient and in equilibrium, the prices paid for FTRs in either an annual or a monthly auction would be expected to closely match the value of day-ahead congestion charges. At the opening of a new day-ahead market, market participants that bid in the FTR auctions may not have sufficient experience with and knowledge of FTRs upon which to base their expectations of day-ahead congestion charges. Low market liquidity at the start of a market may also contribute to the market's inefficiency. Consequently, significant differences between FTR auction prices and day-ahead congestion charges might be expected. This is indeed what occurred in the Midwest ISO's monthly FTR auctions, as illustrated in Figures 46, 47, and 48 for the WUMS Area, the Minnesota Hub, and the Michigan Hub, respectively, all measured relative to the Cinergy Hub, which is the most liquid FTR auction market. The average FTR auction prices in these three markets generally underestimated the actual value of congestion in the day-ahead market in most months. The differences were larger in the western markets—WUMS and Minnesota—than in the eastern markets—Michigan and IMO—due to the fact that the former market regions experienced significant unanticipated day-ahead congestion.

[279] Midwest ISO SOM 2005, Figure 39, p. 55.

Figure 46
Midwest ISO Monthly FTR Auction Value and Day-ahead Congestion Value—Peak and Off-Peak Periods, WUMS Area: 2005[280]

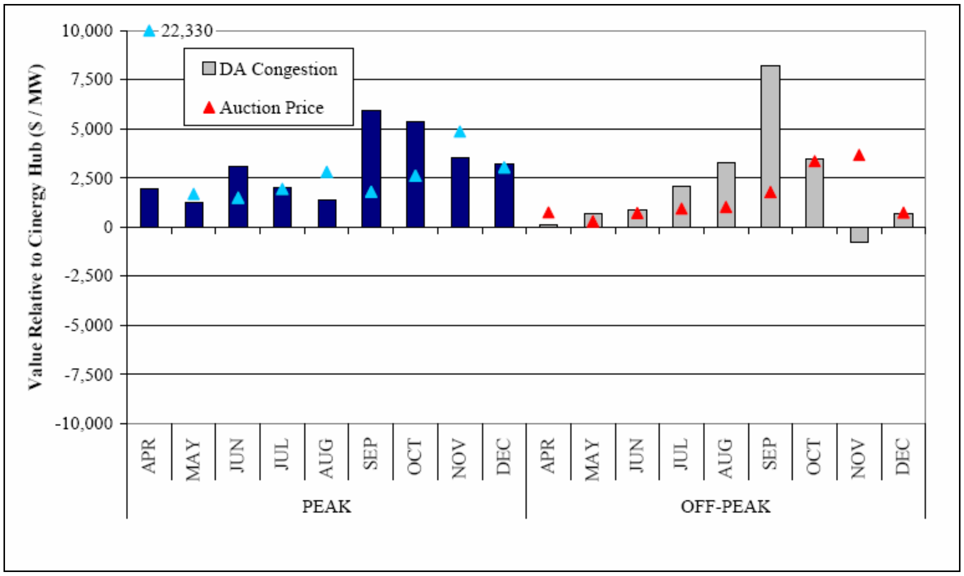
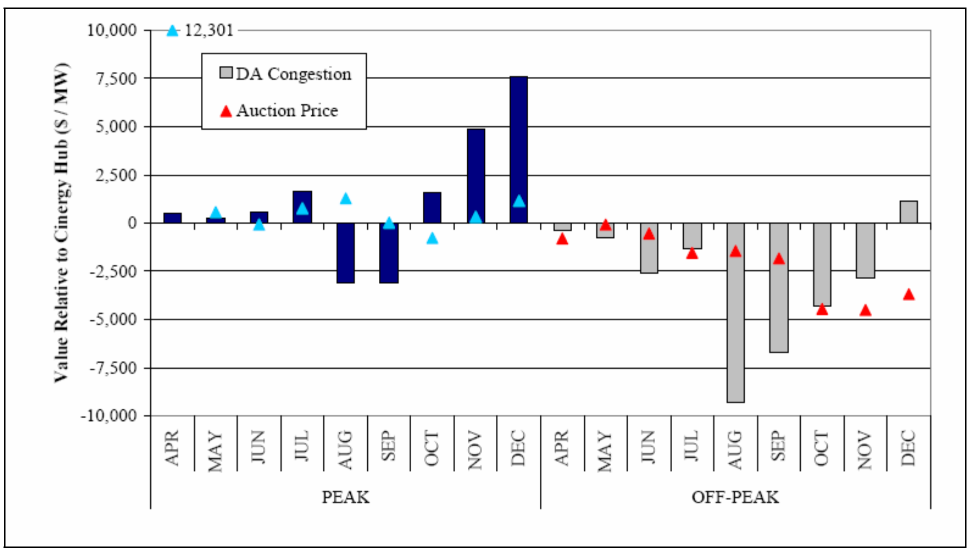


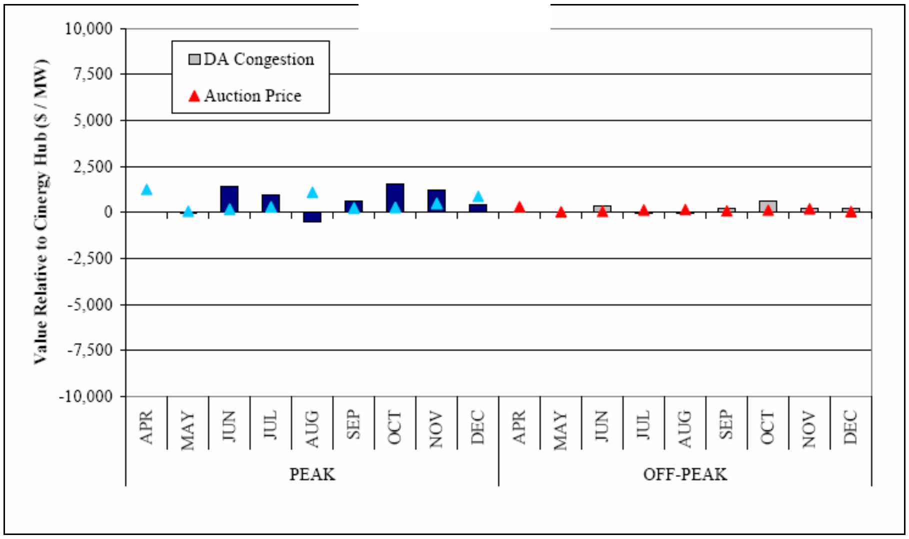
Figure 47
Midwest ISO Monthly FTR Auction Value and Day-ahead Congestion Value: Peak and Off-Peak Periods, Minnesota Hub: 2005[281]



[280] Midwest ISO SOM 2005, Figure 49, p. 70.

[281] *Ibid*., Figure 50, p. 70.

Figure 48
Midwest ISO Monthly FTR Auction Value and Day-ahead Congestion Value: Peak and Off-Peak Periods, Michigan Hub: 2005[282]



4.4. Third RTO

4.5. Summary and Implications

At the national level, miles of high-voltage transmission-lines increased by 0.6% in 2004, in contrast to a 2.3% increase in the electric generating fleet. Although this indicates a continuation of the low level of transmission investment that has existed since the early 1990s, dollars of investment have increased at a rapid 13.1% compound annual rate between 2000 and 2004.

Thus far, the RTOs' transmission planning processes appear to be ineffective, as the RTOs seem to have no authority to mandate the building of economic upgrades nor even to determine that the most cost-effective upgrades ought to be built first. Prioritization of transmission upgrade needs is essential to RTOs' successful implementation of a transmission planning process; and yet, at the present time, it is merely an idea for discussion in some RTOs.

One of the impediments to transmission investment is the arbitrary distinction made in some RTOs between "reliability upgrades" and "economic upgrades." Reliability-based investments always allow reductions in generation redispatch costs that also would be expected to reduce market-clearing prices; and economic-based investments always provide reliability benefits. The distinction is made in the continuing hope that the market will build economic upgrades, but experience throughout the world indicates that this is more a hope than a reality. The unfortunate result of trying to distinguish between "reliability upgrades" and "economic upgrades" is that the distinction has permitted continued under-building of transmission facilities

[282] *Ibid*., Figure 51, p. 71.

that planning processes clearly indicate would provide net benefits to wholesale customers and retail consumers.

4.5.1. Transmission Planning

In PJM, transmission planning has not met the goals of PJM and many LSEs. Of the $2 billion of transmission upgrades that PJM has authorized since 2000, most have been short-term "reliability" upgrades, with most of the remaining upgrades used to interconnect new generation. By contrast, "economic" upgrades, which reduce transmission congestion costs and improve market access, have not yet happened, despite the fact that congestion costs have been increasing on an absolute and per unit basis over the past several years.[283] On the other hands, two major high-voltage transmission projects have recently been proposed that will generally improve west-east flows through PJM, if they are approved and built.

PJM is considering extending the duration of its planning horizon from the current 5 years to up to 15 years, incorporating a new "economic efficiency" component into the Regional Transmission Expansion Plan (RTEP) process, and providing a direct link between the transmission planning process and the creation and maintenance of long-term FTRs. These changes are partly motivated by a desire to induce investment in "economic" upgrades.

In the Midwest ISO, the transmission planning process looks about five years into the future and creates the Midwest Transmission Expansion Plan (MTEP), which identifies "Planned" and "Proposed" transmission projects. The Midwest ISO does not independently evaluate whether these projects are the most efficient solutions to identified reliability issues. Furthermore, these projects apparently include only those that are needed for reliability purposes, not those that allow substantial reductions in congestion and in generation costs. The Midwest ISO intends to recommend congestion-reducing transmission plans when a collaborative stakeholder process determines how to identify such economic projects and how to determine cost responsibility. In summary, the Midwest ISO's transmission planning process assures reliability, but does not necessarily provide least-cost transmission plans either for reliability in isolation or for reliability and congestion together.

Agreement has not yet been reached on the assignment of cost responsibility for transmission expansion, even for reliability upgrades. The costs of load-growth driven upgrades seem to be allocated to the local Transmission Owner constructing the upgrade. The Midwest ISO has proposed that the costs of other projects needed to maintain system reliability be allocated according to Line Outage Distribution Factors, except that 20% of the costs of projects rated 345 kV and higher be allocated regionally through a systemwide rate.

The most recent MTEP shows sharp upward trends in planned, proposed, and total transmission investments through 2008. After 2008, plans apparently become more uncertain, as most investments are merely proposed rather than planned, and the total volume of investments falls.

[283] On the other hand, some major transmission investments have recently been proposed that are likely to have substantial "economic" benefits. These projects appear to have been more the result of the economic incentives embedded in the Energy Policy Act of 2005 than the result of the RTOs' transmission planning processes.

4.5.2. Transmission Congestion

Transmission congestion limits the ability of low-cost generation to reach loads. By limiting the geographic scope of markets, it can also create or exacerbate local market power problems in energy and reserve markets.

In PJM, the overall trend in total congestion costs has been upward since the inception of the LMP-based energy market in 1999. In recent years, the major increases in congestion have been largely due to PJM's expansion, because congestion that was formerly located *outside* of PJM has suddenly become located *inside* of PJM. On a per-MWh basis, congestion costs have actually gone down. Consequently, it is not clear whether the integration has resulted in any significant change in congestion for the region that PJM now encompasses; and it is possible that PJM's expansion has resulted in scale economies that have reduced congestion costs.

Similarly, although the frequency of congestion events within PJM has increased over time, there were overall decreases in congested hours experienced on most interfaces, transformers, and lines during 2004 as compared to 2003, but generally increases in congested hours for 2005 compared to 2004. Because 2004 had a mild summer peak period, 2005 witnessed overall increases in congested hours compared to 2004.

In the Midwest ISO, prior to the April 2005 introduction of LMP and the Day 2 Market, there were significant problems with TLR calls (i.e., transmission service curtailments) and rejections of short-term reservation requests. In fact, during the years 2002 through 2004, most requests were refused. The problems with TLRs were so bad that, in 2004, Midwest ISO flowgates accounted for most of the TLR calls in the Eastern Interconnection, with the WUMS regions experiencing more TLRs than any other Midwest ISO region.

The Day 2 Market has had little effect on the *number* of TLR calls, but substantial effect on the GWh *volume* of TLR calls. The number of calls was down only slightly in 2005 relative to 2004; but the GWh volume of TLR calls declined by 76% from 2004 to 2005. Because the cost of TLR calls is related to the GWh volumes, the Day 2 Market has apparently improved the efficiency of congestion management.

Nonetheless, the Midwest ISO has to contend with some serious congestion issues, some of which may be resolved with experience and with improvements in market design. These issues include the following:

- In 2005, an astonishing 25% of Day 2's congestion was "unmanageable," meaning that the ISO was unable to keep transmission flows within the bounds of transmission constraints on a 5-minute basis. The IMM says that this problem arises from generators' unwillingness to offer the redispatch capability that they have, and from a Midwest ISO modeling rule that limits Midwest ISO's ability to redispatch certain generators, even when those generator are willing to help manage transmission constraints. The IMM has proposed remedies for these problems.
- When constraints are unmanageable, LMPs are mathematically undefinable. Under such circumstances, the Midwest ISO produces LMPs by resorting to a mathematical trick that underprices congestion. The IMM has proposed a remedy that will improve the pricing but will not fully solve the pricing problem.

- Congestion costs in the real-time market were almost a third of the total congestion costs. This large level of real-time congestion costs indicates significant day-ahead misforecasts of line limits, external loop flows, and other factors.

4.5.3. Transmission Rights

In PJM over the past several years, market participants have generally received about three-fifths of the transmission rights that they want, and those rights have generally been worth about 95% of their nominal values. The net result is that just over half of transmission congestion is hedged, while the unhedged remainder imposes risks that are ultimately borne by customers, especially those in load pockets.

PJM has not yet developed a market for long-term transmission rights. Rights are presently available for no more than one year into the future, with essentially automatic annual renewal of those rights based upon historic usage. Participant working groups are currently discussing proposals that would establish and allocate a portion of FTRs for up to a ten-year period. FERC Order No. 681 gives new impetus to these proposals.[284]

PJM has recently had stable or falling prices for FTRs of up to one year's duration, a development that, if it continues, could reduce risk in the short-term FTR market.

In the Midwest ISO, Financial Transmission Rights (FTRs) were fully funded in 2005: the rights were worth 100% of their nominal values. Increasing loop flows between PJM and TVA create congestion problems for the Midwest ISO and threaten to undermine the values of the Midwest ISO's FTRs; so the RTOs are attempting to resolve the underlying seams problems.

In the Midwest ISO's monthly FTR auctions, the average FTR auction prices generally underestimated the actual value of congestion in the day-ahead market in most months of 2005. The differences were larger in the western markets—WUMS and Minnesota—than in the eastern markets—Michigan and IMO—due to the fact that the former market regions experienced significant unanticipated day-ahead congestion.

5. DEMAND RESPONSE

Demand response is important because it can induce more competitive behavior among suppliers and limit suppliers' ability to exercise market power. Furthermore, if customers can respond to hourly prices, then suppliers would have the incentive to deliver power on a more cost-effective basis, consistent with their customers' valuations. An effective demand side of the electricity market does not require that all customers curtail usage in response to rising prices. It instead requires that many customers (or their agents) have the ability to see and respond to hourly prices. Hence, the effectiveness of demand-side response is a matter of degree, and depends upon the extent to which demand can and does respond to market conditions.

Although markets function most effectively when there is a demand-side response to market conditions, few customers receive information or signals on current market conditions—except

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[284] Federal Energy Regulatory Commission, Order No. 681, *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Docket No. RM06-8-000, July 20, 2006.

during extraordinary broadcast appeals for conservation during emergencies—and so most demand is not responsive to current market conditions.

5.1. PJM

Table 39 shows a recent breakdown of demand-side programs in the PJM territory at September 2004 and November 2005.[285] Of the 11,660 MW of responsive load in 2004, PJM itself was directly responsible for 3,598 MW, another 7,331 MW "is exposed to real-time prices either directly or through an intermediary competitive supplier…."[286] and 731 MW are programs that curtail customer loads. The 11,660 MW of responsive load constituted 8% of PJM's total generating capacity of approximately 144,000 MW in 2004.

In 2005, there were 10,194 MW of responsive load, constituting 6% of PJM's 163,000 MW of generating capacity. This volume of responsive load is less than that of 2004 in both absolute and relative terms: while total capacity rose with PJM's expansion, responsive load fell. PJM's own demand-response programs rose substantially, however to 5,634 MW. It was the non-PJM price-based programs that fell, by more than half, to 3,653 MW. On the other hand, the non-PJM curtailment programs rose to 907 MW. In relative terms, PJM's own programs rose from 31% of the total in 2004 to 55% in 2005, while non-PJM price-based programs fell from 63% to 36% and non-PJM curtailment programs rose from 6% to 9% of the total.

Table 40 takes a closer look at the PJM programs summarized above in Table 39. The lion's share of demand response comes from the real-time option of the Economic Load Response Program. The real-time load response option offers end-use customers the opportunity to reduce their energy consumption from the PJM system during times of higher than average prices and receive payments for their reductions based on the real-time LMP. To encourage customers to reduce consumption when PJM LMP prices are high, the program subsidizes load reductions by paying customers more than strict economics indicate that curtailments are worth. These subsidies are supposedly justified as a means of overcoming initial barriers to customer load response. This program is not intended to be a permanent fix to the dearth of customer load response seen in the PJM markets today. The designers of this program hope that when the existing market barriers are removed and customers are better able to respond to real-time prices, the need for this program and others like it will disappear.

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[285] We presume that the LSE and independent programs were the same in both time periods; but due to changes in nomenclature, we are unable to directly match these programs across years.

[286] PJM 2004 SOM Report, p. 94.

Table 39
Demand Response Programs (MW) in PJM[287]

	Sept 2004	Nov 2005
PJM Programs		
PJM Economic Load-Response Program	724	2,210
PJM Emergency Load-Response Program	1,385	1,619
PJM Active Load-Management Resources	1,806	2,065
Less Duplication	-317	-260
Total PJM Programs	3,598	5,634
LSE and Independent Price-Based Programs		
Competitive LSEs Load – Partial Exposure to LMP		2,012
Competitive LSEs Load – Other Contract Mechanism		425
Distribution LSEs LMP Based Load		1,216
Competitive Contracts	4,436	
Independent Price-Responsive Load on Pilot Programs	203	
Direct Customer Purchases Based on LMP Signals	2,692	
Total MW with Full and Partial Exposure to Real-Time LMP	7,331	3,653
LSE and Independent Curtailment-Based Programs		
Competitive LSEs Curtailable Load		224
Distribution LSEs Direct Load Control Load not in ALM		289
Distribution LSEs Other Demand Response not in ALM		14
Distribution LSEs Other (Price Sensitive) Regulated Retail Rate Load		212
Distribution LSEs Reported Regulated Interruptible Load		168
Independent Interruptible Load Programs	453	
Independent Emergency Load-Response Programs of EDCs	278	
Total MW under DSR Programs Administered by LSEs in PJM Territory	731	907
Total Programs	11,660	10,194

[287] PJM 2004 SOM Report, Table 2-42, p. 95, and PJM 2005 SOM Report, Table 2-17, p. 82.

Table 40
PJM Demand Response Program Results
2004[288]

	Program Type	Achieved Reduction (MWh)		Program Enrollment (MW)		Enrollment as % of Peak Load	
		2004	2005	2004	2005	2004	2005
Economic Load Response Programs:							
Day-Ahead Option	Bid-based	179	38,140	724	2,210	0.7 %	1.7%
Real-Time Option	Price Taker	46,561	75,253				
Non-hourly, Metered Program	Varies	1,881	No Activity	NA	No Activity		
Emergency Load Response Program	Curtailment	0	3,362	1,385	1,619	1.3%	1.2%
Active Load Management (ALM)	Curtailment	0	Not reported[289]	1,806	2,065	1.7%	1.5%
Less Duplication				(317)	(260)		
Totals		48,622		3,598	5,634	3.4%	4.2%

The PJM Economic Load Response program also offers a day-ahead load response option that offers end-use customers the opportunity to commit to a load reduction in advance of real-time operations. Participating customers receive payments for their reductions based on the day-ahead LMP. Relatively small amounts of load reduction come from the day-ahead load response option.

The PJM Economic Load Response Program also includes a Non-hourly, Metered Program. This also provides relatively little load relief. PJM created this program to extend participation in the demand side of the market to smaller customers that lack hourly meters. This pilot program allows such customers (or their representatives) to propose alternate methods for achieving measurable load reductions. PJM approves such methodologies on a case-by-case basis.

Tables 41 and 42 show the growth over the period 2001 to 2005 in the emergency and economic load response programs in PJM. Both programs have been growing in numbers of registered participants and total MW. The Economic Load response program has also been experiencing an increasing number of MWh of reduced load produced by participants. Nonetheless, the numbers of participants and MWh remain small relative to the potential numbers. Table 40 indicates that the price per MWh of the program (the payment in the form of a credit to the load for actual reduction in demand) declined until 2004, and then rose sharply in 2005. According to PJM, the costs to administer the program are $20,000 per year, which in 2004 meant, for the first time, the

[288] PJM 2004 SOM Report, Table 2-41, p. 90 and Table 2-42, p. 95, and PJM 2005 SOM Report, Table 2-17, p. 82.

[289] PJM reports that it interrupted loads on the ALM program twice during the summer of 2005, July 27 and August 4, but it does not report the MWh of those interruptions. PJM 2005 SOM Report, p. 76.

program administration cost fell below $1/MWh.[290] Program costs in 2005 were about $0.18 per MWh.

Table 41
PJM Currently Active Participants in Load Response Programs at Year End Cumulative 2001 – 2005[291]

Year	Economic Load Response Program		Emergency Load Response Program	
	Sites	***MW***	***Sites***	***MW***
2001	NA	NA	NA	NA
2002	106	321	64	515
2003	248	469	167	663
2004	2,466	1,644	3,873	1,558
2005	2,590	2,210	3,885	1,619

In spite of the foregoing, PJM is concerned about the limited exposure and response of customers to real-time wholesale prices.

Table 42
PJM Economic Load Response Program Performance: 2001 – 2005[292]

Year	Total MWh	Total Payments	$/MWh
2001	50	$ 13,994	$283
2002	6,727	$ 801,119	$119
2003	19,518	$ 833,530	$ 43
2004	58,352	$ 1,917,202	$ 33
2005	113,393	$12,000,354	$106

5.2. Midwest ISO

The Midwest ISO has not yet developed demand response at the RTO level.[293] However, the Midwest ISO has recently reactivated the Demand Response Task Force to address demand response issues. This comes partly in reaction to the Midwest ISO's curtailment requests made during the hot summer of 2006.

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[290] The cost per MWh is obtained by dividing the total cost of $20,000 per year (as reported by PJM) by the total MWh in 2004, which is reported as 58,352 MWh in Table 37.

[291] Source, Howard J. Haas, *MADRI AMI Workshop presentation*, PJM Market Monitoring Unit, May 4, 2005. Obtained from http://www.pjm.com/markets/market-monitor/downloads/mmu-presentations/20050504-ami-pjm-mmu-pres.pdf , accessed 1/23/06.

[292] PJM 2004 SOM Report, Table 2-40, p. 88 and PJM 2005 SOM Report, Table 2-15, p. 75.

[293] Additional information on demand response programs operated at the local level was not available at the time of writing.

5.3. Third RTO

5.4. Summary and Implications

Although markets function most effectively when there is a demand-side response to market conditions, the demand side of almost all electricity markets is underdeveloped. In almost all markets, few customers receive information or signals on current market conditions—aside from the extraordinary broadcast appeals for conservation during emergencies—and so most demand is not very responsive to current market conditions.

In PJM, there are about 10,000 MW of responsive load, which constitutes about 6% of its total generating capacity. Of this responsive load, PJM itself is directly responsible for 55%, 36% is exposed to wholesale prices, and 9% is enrolled in independent demand-side response programs.[294]

In the Midwest ISO, there are no demand response programs at the RTO level.

6. RTO PERFORMANCE

This section looks at two aspects of RTO performance.

First, "control performance" is the success with which a system operator balances supply and demand. System operators manage power imbalances primarily through automatic dispatch of regulating resources, and secondarily through dispatch of spinning and non-spinning reserves. For a power system located on an island, the balance between supply and demand would be measured by how closely the power system is able to achieve its target frequency (e.g., 60 Hz); while for power systems like PJM and Midwest ISO that are located in the midst of the Eastern Interconnection, the balance is measured by unscheduled power flows into or out of the control area. These unscheduled power flows are quantified by CPS1 and CPS2 criteria, the first of which measures how large the unscheduled power flows are at any point in time, while the second measures the accumulation of these unscheduled flows over time.

Second, RTOs may be evaluated according to how well that they provide several administrative services. These services can include settlements, transmission service billings, dispute resolution, and interconnection studies. RTOs' performance might be measured according to the speed of final settlements, timeliness of transmission service billings, frequency of billing and/or tariff administration disputes, and speed of interconnection studies.

As a practical matter, measures of control performance are available, while measures of administrative performance are difficult to obtain. The reason is that national and regional reliability councils require control operators to keep records of control performance, but there is no similar requirement for recordkeeping of administrative performance. Consequently, for the time being at least, we will look at RTOs' control performance and will leave evaluation of administrative performance for some future time.

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294 Percentages may not add to 100% due to rounding.

6.1. PJM

PJM's 2004 SOM Report says that:

> "PJM generally performed well in 2004 against the CPS1 and CPS2 metrics. Nonetheless, the Phase 2 integration of the Commonwealth Edison Company (ComEd) Control Area and the Phase 3 integration of the AEP and DAY Control Zones into the PJM Control Area created two especially difficult problems. First, the establishment of the ComEd Control Area left that region without enough available regulation to meet the regulation requirement. The subsequent incorporation of the ComEd, AP, AEP and DAY Control Zones into a single PJM Control Area during Phase 3 required PJM to adapt its frequency management to a new frequency bias constant and new interchange transaction characteristics."[295]

Similarly, PJM's 2005 SOM Report says that:

> "While PJM passed the CPS performance standard in 2005, PJM's performance with respect to these metrics remains an area of concern… [PJM's] CPS1 and CPS2 scores for 2005 are generally lower than they were in 2004 and generally lower since Dominion integration (Phase 5) on May 1, 2005. CPS1 and CPS2 standards are pass/fail so this decline is not a problem as long as PJM meets the CPS1 and CPS2 control standards."[296]

In other words, PJM believes that it is managing power imbalance well, but that it has experienced some growing pains in connection with its expansion. Consistent with PJM's concerns, Figure 49 indicates that PJM's control performance has declined over time.

6.2. Midwest ISO

We have no statistics or data on the quality of Midwest ISO's control performance and administrative services. We do know, however, that Midwest ISO has a State Estimator and Contingency Analysis Tool that analyze data from more than 96,000 grid locations and consider more than 5,000 potential contingencies every eight minutes.[297]

6.3. Third RTO

6.4. Summary and Implications

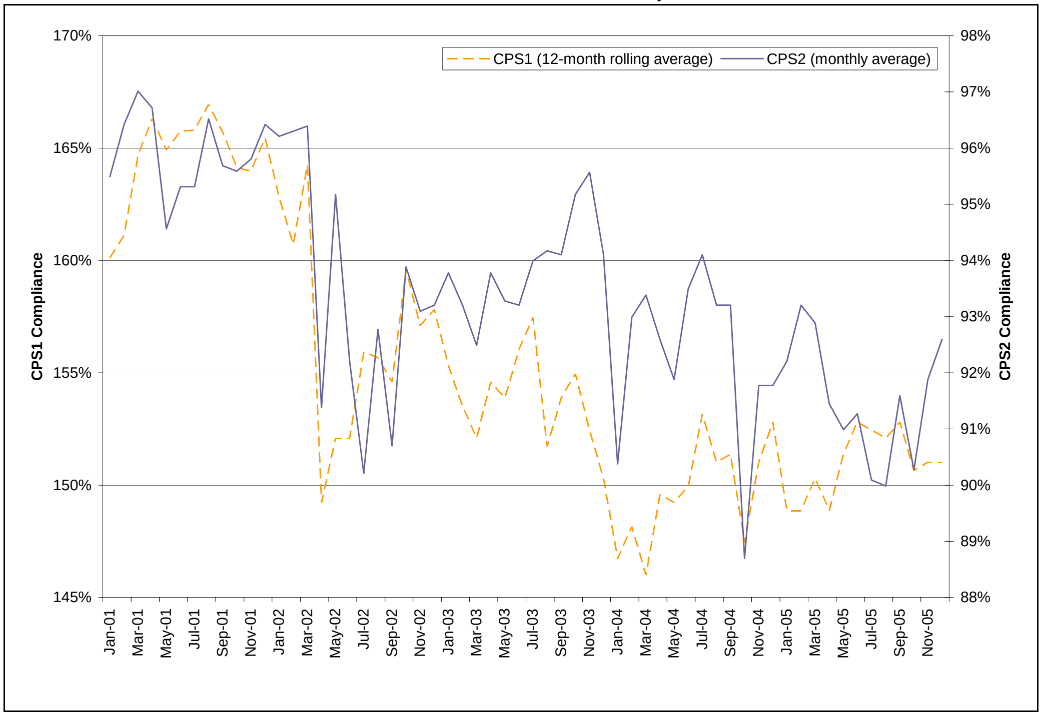
PJM believes that it is managing power imbalances well, but that it has experienced some growing pains in connection with its expansion. The evidence indicates, however, that PJM's control performance has declined over time as it has expanded, as both CPS1 and CPS2 have been on decidedly downward trends from 2001 through 2005. Nonetheless, with rare exceptions in the fall of 2004, PJM has complied with CPS1 and CPS2 targets.

[295] PJM 2004 SOM Report, p. 320.

[296] PJM 2005 SOM Report, p. 420.

[297] 2004 Annual Report, p. 12.

Figure 49
PJM CPS1 and CPS2 Performance, 2001 – 2005[298]



7. MISCELLANEOUS COSTS

This section looks at three broad categories of costs that are ultimately borne by consumers within RTO footprints. These are uplift charges, RTO administrative costs, and the direct costs of RTO participation.

"Uplift charges" are monies that customers are required to pay to RTOs for certain non-administrative costs incurred by the RTOs. These costs primarily consist of payments to generators in excess of the revenues the generator would receive by making sales through the ISO's organized wholesale markets. These payments may be for any of the following:

- "reliability must run" service;
- out-of-merit dispatch;
- voltage support;
- out-of-market payments to ensure generator availability during peak demand periods;
- out-of-market payments to certain customers to allow the RTO to curtail their demands on short notice;

[298] PJM 2004 SOM Report, Figure F-1, p. 320, and PJM 2005 SOM Report, Figure F-1, p. 420.

- intra-settlement period costs[299] not reflected in LMPs;
- allocations of shortfalls in FTR revenue adequacy; and
- RTO operating costs not allocated in another manner.

In some cases the foregoing costs are allocated to and socialized across the sub-region experiencing the reliability problem, while in other cases the costs are socialized across all participants in the RTO.

RTO administrative costs include the costs of administering energy, ancillary service, capacity, and FTR markets; the costs of administering the Open Access Same-Time Information System (OASIS) and the transmission tariff; and the costs of responding to interconnection requests and conducting transmission interconnection and transmission expansion studies. These costs are recovered through a series of charges to RTO members and market participants that are included as schedules in the open access transmission tariff administered by the RTO. Such costs are often recovered from market participants in proportion to their MWh loads.

The direct costs to utilities and other market participants of RTO market participation include the costs of employees that must be hired to interact with the RTO, and the costs of communication software and hardware so that utilities can manage the flow of information to and from the RTO. Additional costs are associated with accounting and settlements management and legal and meeting expenses associated with monitoring and responding to the actions of the RTO.

7.1. PJM

7.1.1. Uplift Charges

A source of uplift costs in the PJM RTO is payments to generators for providing operating reserve services. Operating reserve payments are made to resource owners under specified conditions in order to ensure that units are not required to operate for PJM at a loss. These payments provide an incentive for generation owners to offer their energy to the PJM market at marginal cost and to operate their units at the direction of PJM dispatchers. If a unit is selected to operate in the PJM Day-Ahead Energy Market on the basis of its offer and that unit's revenues from this market are insufficient to cover all the components of the unit's offer, including startup and no-load offers, operating reserve payments ensure that all offer components are covered.[300]

Table 43 shows total operating reserve payments from 1999 through 2005. A number of significant market changes have occurred during this period. Energy markets clearing on the basis of market-based generator offers were initiated on April 1, 1999. Thus the 1999 operating reserve total includes operating reserve payments for three months based on generators' marginal

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[299] "Intra-settlement period costs" are payments to high-cost generators that operate for only a portion of a billing hour at a cost higher than the weighted average LMP for the whole hour. In other words, these costs arise from the convention of setting wholesale prices hourly, even though costs actually vary by 5-minute dispatch interval.

[300] Operating reserve payments are also made for pool-scheduled energy transactions, for generating units operating as condensers rather than as spinning reserve, for the cancellation of pool-scheduled resources, for units backed down for reliability reasons, and for units providing quick-start reserves.

cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Thus operating reserve payments for 1999 and the first five months of 2000 include only operating reserve payments made in the Real-Time Energy Market. Beginning on June 1, 2000, operating reserve payments include both day-ahead and real-time operating reserve payments.

Table 43
Total PJM Day-Ahead and Real-Time Operating Reserve Payments
1999 to 2005[301]

Year	Day-Ahead Payment (millions)	Real-Time Payment (millions)	Total Annual Payment (millions)	Operating Reserve Payments as % of Total Billing	Day-Ahead $/MWh	Real-Time $/MWh
1999	N/A	$ 54	$ 54	3.0	N/A	N/A
2000	$ 60	$ 87	$147	6.5	$0.34	$0.53
2001	$ 80	$171	$251	7.5	$0.27	$1.07
2002	$ 60	$129	$189	4.0	$0.16	$0.79
2003	$ 87	$187	$274	4.0	$0.23	$1.20
2004	$129	$249	$379	4.4	$0.23	$1.24
2005	$60	$541	$601	2.7	$0.08	$2.76

The first three columns of Table 43 show the total dollar values of operating reserve payments. Between 2001 and 2002, operating reserve payments declined by about $62 million, or 25%. Between 2002 and 2003, operating reserve payments rose by approximately $85 million or 45%. Between 2003 and 2004, operating reserve payments rose by approximately $105 million or 38%. Between 2004 and 2005, these payments rose by another $222 million or 59%. However, these increases are primarily associated with PJM's expansion. The increased operating reserve charges in 2005 were also due to transmission outages and market power.[302]

Because of PJM's expansion, the more meaningful figures appear in the three rightmost columns, which present figures that are implicitly normalized for the expansion. The column labeled "Operating Reserve Payments as % of Total Billing" shows that operating reserve payments have varied between 2.7% and 7.5% of total billings, with a peak occurring in 2000 and 2001 during the aforementioned reserve market spike. Overall, the average has been about 4%.

The two rightmost columns of the table show shows day-ahead and real-time operating reserve payments on a per-MWh basis. Day-ahead operating reserve costs are recovered from day-ahead energy load, accepted decrement bids, and exports. The per-MWh charge equals these costs divided by the sum of the foregoing load, bids, and exports. Real-time operating reserve costs are recovered charged to market participants whose real-time transactions deviate from their day-ahead schedules. The per-MWh charge equals these costs divided by the sum of the load,

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[301] PJM 2004 SOM Report, Table 2-43, p. 96 and PJM 2005 SOM Report, Table 3-26, p. 154.

[302] PJM 2005 SOM Report, p. 30.

generation, and transaction deviations relative to the day-ahead schedules. The transaction deviations include deviations that result from cleared virtual bids or offers from the Day-Ahead Energy Market that were not subsequently delivered in the Real-Time Market.

The two rightmost columns show wide fluctuations in per-MWh values, with an apparent downward trend in the day-ahead market and an apparent upward trend in the real-time market. It is also very notable that the per-MWh cost in the real-time market is far higher than in the day-ahead market, which reflects the facts that: a) the real-time costs are roughly double the day-ahead costs; and b) the denominator of the real-time price (deviations) is smaller than that of the day ahead price (total load and other sinks).

7.1.2. RTO Administrative Costs

Figure 50 graphically summarizes PJM's total operating costs (including administrative costs) for each of the years 1999 to 2006. Total operating costs are expressed on a dollar per MWh basis in Figure 51. While PJM's administrative costs generally have been increasing in absolute terms, and experienced a significant jump in 2002 and a slight jump in 2005, they have displayed a general downward trend since 2002 on a per-unit basis. The jump in total operating costs in 2005 reflects the cost impact of the PJM expansion: this cost impact includes recovery of depreciation and deferred depreciation related to market integration assets that began on January 1, 2005. The decline in per-MWh operating cost over the past several years suggests that PJM has begun to experience some economies of scale and scope through growth in transactional volumes and through its expansion and integration of the six additional utilities in 2004 and early 2005.

Excluding FERC fees, the total operating budget for 2005 is $277 million and will drop in 2006 to $255 million.

Beginning on June 1, 2006, PJM introduced a "stated rate" for its administrative charges, under which these charges are fixed for a term of five years. The "stated rate" was created to provide multi-year service price certainty and improved cost transparency. PJM is also committed to a five-year series of rate cuts.[303]

[303] PJM Interconnection, *PJM to Implement Fixed Administrative Rates*, news release, May 31, 2006.

Figure 50
PJM Total Operating Expenses 1999 – 2006[304]

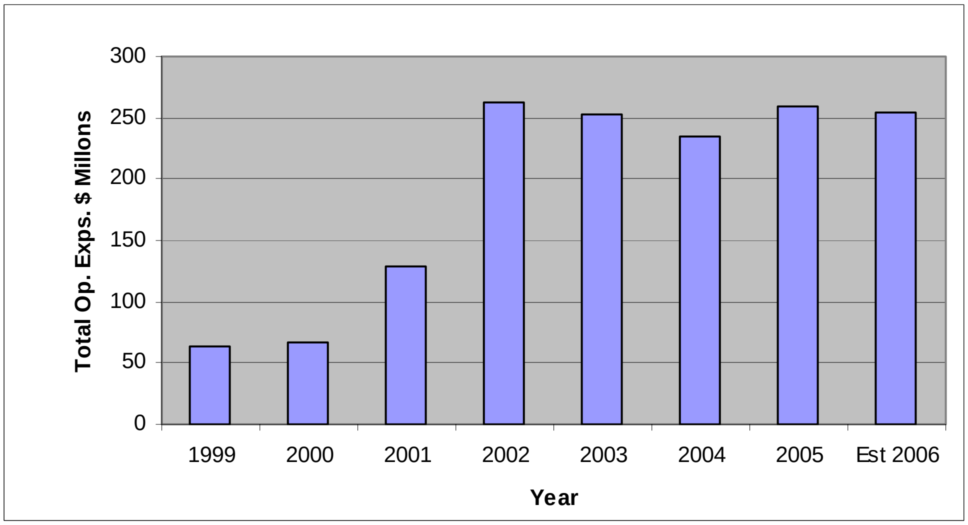
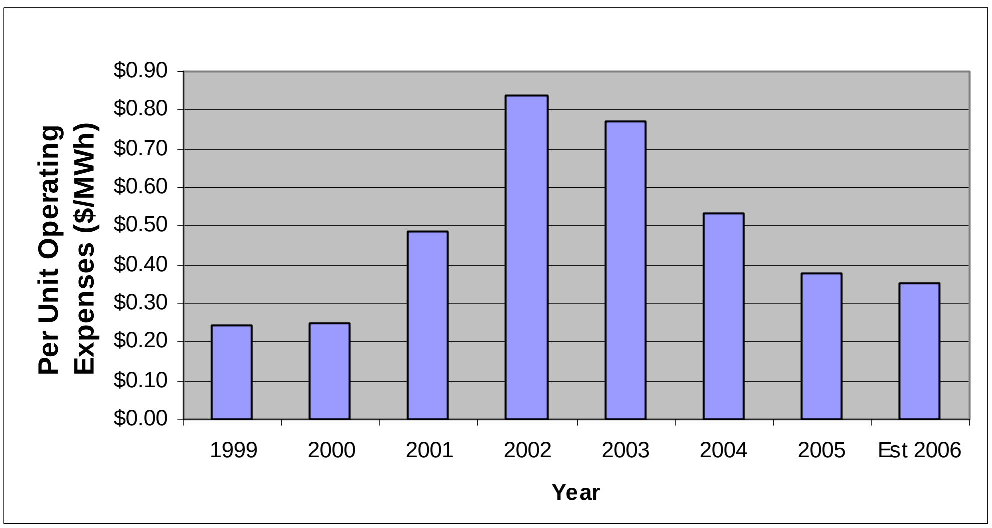


Figure 51
PJM Per-Unit Operating Costs, 1999 – 2006 ($/MWh)[305]



7.1.3. Direct Costs to RTO Market Participants

Joining an RTO or even participating in an RTO's day-ahead and real-time power markets imposes certain direct costs on participants, most of which are in the form of administrative expenses. Some of the costs are in addition to existing administrative expenses while others

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[304] PJM FERC Form 1, 1999 to 2005. The estimate for 2006 is from the PJM Approved 2006 Budget.

[305] Operating Expense data are from PJM FERC Form 1 for the years 1999 to 2005, and the PJM Approved 2006 Budget. MWh and hourly load data for 1999-2005 are from http://www.pjm.com/markets/jsp/loadhryr.jsp. 2006 hourly load is estimated using the 2005 and 2006 PJM Load Forecast Reports.

merely replace administrative costs that would be borne even in a world without RTOs and centralized power markets. Some of the more important direct cost categories that RTO members and market participants must bear are as follows:

- *RTO application and membership fees* (on the order of $5,000 per year).
- *Meeting RTO credit requirements*.
- *Information and communication technology investments*. These include the costs of the hardware, software, and personnel needed to satisfy RTO requirements, to manage information and data exchange with the RTO, and to analyze the accuracy of all data (notably including billing data).
- *RTO generation scheduling and dispatching costs*. These costs could be higher or lower than the costs of self scheduling and dispatching the participant's own generation units.
- *Handling invoices and money transfers for settlements*.
- *RTO imposed hardware and software requirements*. There requirements may increase participant's fixed or operating costs. On the other hand, if a utility that manages a Control Area joins an RTO and relinquishes many or all of its operating responsibilities to the RTO, the participant's operating costs may be reduced.
- *Other transaction costs*. These include the costs of attending RTO meetings, monitoring FERC filings, and intervening, when necessary, in FERC proceedings.

Unfortunately, there is a dearth of publicly available data on these direct costs; and anecdotal evidence is not helpful in drawing conclusions. It may nonetheless be possible to systematically collect data on these cost categories and develop a quantitative measure of the direct costs of RTO participation over time.

7.2. Midwest ISO

Midwest ISO's Statement of Operations show that Midwest ISO's expenses substantially exceeded its revenues in 2003, 2004, and 2005, by $48 million, $51 million, and $10 million, respectively. Midwest ISO does not record this as a loss, but instead books the excess expense as a Deferred Regulatory Asset that will be recovered through revenues at some later date. Midwest ISO's balance sheet sets Deferred Regulatory Assets equal to the amount by which Total Liabilities exceed Total Assets (excluding Deferred Regulatory Assets). Of $738 million of Total Assets at the end of 2005, $166 million are Deferred Regulatory Assets, which are past losses that Midwest ISO intends to recover at some future date.[306]

7.2.1. Uplift Charges

There are three major sources of uplift charges in the Midwest ISO RTO: Revenue Sufficiency Guarantee (RSG), Revenue Neutrality Uplift, and System Support Resources. We discuss each of these in turn.

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[306] Midwest ISO 2005 Annual Report, p. 23.

7.2.1.1. Revenue Sufficiency Guarantee

As explained in Section 3.2.2, Revenue Sufficiency Guarantee (RSG) payments guaranteed cost recovery for generation resources committed by the Midwest ISO. These RSG payments are funded out of "RSG Distribution charges" to market participants. The RSG payments are passed on to market participants according to their total loads purchased in the real-time energy market during the operating day, their uninstructed deviations, and their virtual supply offers in the day-ahead market. RSG costs are recovered from all loads—even those that self-schedule their own resources—on the theory that all loads benefit from RSG resources' reliability services.[307]

Since the start of the Day 2 Market, the Midwest ISO has not included virtual supply offers in calculating RSG charges to market participants, in clear violation of its tariff. The Midwest ISO filed a request at FERC to change its tariff to comport with its actual billing practice. On April 25, 2006, FERC affirmed that the tariff language is controlling, and ordered that RSG charges be assessed on each virtual trade that results in real-time physical power delivery, even if the physical delivery is only a tiny percentage of the virtual trade. FERC further ordered retroactive charges and credits for the differences between the Midwest ISO's past RSG settlements and the tariff requirements.[308]

7.2.1.2. Revenue Neutrality Uplift

Revenue Neutrality Uplift is a compilation of the following six uplift categories:[309]

- ***Uninstructed Deviation Charge Distribution Uplift***: This uplift provides Participants with a credit from Uninstructed Deviation Penalties paid by generation asset owners who do not follow MISO dispatch signals within a tolerance bandwidth. This "uplift" is actually a credit.
- ***Revenue Inadequacy Uplift***: This uplift assures that Midwest ISO's market revenues and expenditures are identical in each hour. Day-Ahead hourly revenue shortfalls are first funded from the hourly Day-Ahead Congestion fund when there are funds, then through this uplift. Real-Time hourly revenue shortfalls are first funded from the hourly Real-Time Congestion fund, then through this uplift. This uplift is generally a charge to market participants, but it can sometimes be a credit.
- ***Joint Operating Agreement Uplift***: Joint Operating Agreements among neighboring ISOs (and RTOs) that enable each ISO, on an hourly basis, to request another ISO to make additional flowgate capacity available to the requesting ISO. The costs incurred to meet such requests are paid by the requesting ISO. If Midwest ISO is a net recipient of such inter-ISO payments, this uplift is a credit. If Midwest ISO is a net payer, the

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307 Midwest ISO Answer 1/9/06, pp. 4-5.

308 Federal Energy Regulatory Commission, *Order Requiring Refunds, and Conditionally Accepting in Part, and Rejecting in Part Tariff Sheets*, Docket No. ER04-691-065.

309 Discussion of these items is based on Midwest ISO, "FAQ-Revenue Neutrality Uplift," found at http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-7ff30a48324a/_.pdf?action=download&_property=Attachment.

payments are first funded by any available funds in the Day-Ahead or Real-Time Congestion Funds, then by this uplift.

- ***Option B Grandfathered Agreement (GFA) Financial Bilateral Transaction Congestion Rebate Distribution Amount Uplift:*** Midwest ISO is obligated to pay the congestion costs that would otherwise be payable by certain owners of GFA transmission rights. Midwest ISO meets these obligations first from the revenues of FTRs that Midwest ISO holds for this purpose, and then through this uplift.
- ***Carve-Out GFA Congestion Rebate Distribution Amount Uplift*****:** This uplift is essentially identical to the previous uplift, except that the two uplifts cover different sets of GFAs.
- ***Real-Time Revenue Sufficiency Guarantee Make Whole Payments Second Pass Distribution Uplift*****:** This uplift addresses inaccuracies in accounting for the energy that serves as the basis for determining the RSG First Pass Distribution amounts billed to market participants as described in Section 7.2.1.1. The inaccuracies sometimes result in receipts from market participants through the RSG First Pass Distribution that are less than RSG payments to generators. Consequently, this deficiency is recovered through the RSG Second Pass Distribution, which is socialized to all market participants as an uplift.

The Revenue Neutrality Uplift is recovered from (or credited to) customers on a Load Ratio Share basis.

7.2.1.3. System Support Resources

System Support Resources (SSRs) are generators that the Midwest ISO commits primarily for reactive power support, where the ISO cannot otherwise meet reliability standards. The Midwest ISO purchases the services of these units for 12-month periods. SSR units are made whole for no-load and start-up costs. The payments to SSRs are recovered by the SSRs under Schedule 2 for provision of Reactive Supply and Voltage Control Services, and are recovered from customers through an uplift charge to all LSEs and transactions in the Control Area where the facility is located.

7.2.2. RTO Administrative Costs

Midwest ISO's operating costs for 2006 will be about $150 million, $10 million less than initially budgeted. Midwest ISO credits the cost reduction to its increasing experience with operating the Day 2 market. The budget reductions fall primarily in the Information Technology and Operations areas. The cost cuts were partly motivated by Midwest ISO's desire to mitigate the adverse impacts of the two Kentucky utilities' withdrawal on other Midwest ISO members.[310]

[310] Midwest Independent Transmission System Operator, *Midwest ISO Trims Operating Costs*, news release, June 19, 2006.

7.3. Third RTO

8. NET BENEFITS AND COSTS TO CONSUMERS

In principle, there are two major categories of benefits of power industry restructuring—and indeed, of the introduction of competition into power markets. These are:

A. reductions in power production (generating) costs that arise from the more efficient power system dispatch that accompanies the lowering of barriers to trade among market participants; and

B. improvements in the management of generating facilities and in generating technologies.

Both of the preceding sorts of benefits are induced by the profit-making and cost-reducing incentives of competition.

On the other hand, there are four major categories of costs of power industry restructuring, which are partly inherent in service unbundling and partly due to the creation of RTOs. These are:

C. higher costs of generation and transmission due to the lost coordination in joint planning of these services;

D. higher costs of financial risks to both suppliers and consumers due to increased price volatility;

E. costs of investment delays due to uncertainty in market design and increased uncertainty in regulatory outcomes; and

F. costs of implementing and participating in RTO markets.

Items A and F are the easiest to quantify, and so (not surprisingly) are the focus of most studies of RTO benefits and costs. The other items are likely to be as large, and perhaps even larger, than items A and F; but they are difficult to quantify because of data limitations and, more importantly, because they require knowledge of an alternative world that does not and will not exist. Consequently, these other items are usually ignored or briefly mentioned in passing.[311] These difficulties prevent the present study from providing quantitative results on the net benefits and costs to consumers.

Nonetheless, we may note that the net benefits and costs to consumers should be measured first and foremost according to the welfare gains or losses that arise from RTOs. This measurement should ideally be performed for a complete power industry business cycle, including both the boom period (when prices are high) and the bust period (when prices are low). Ideally, we would provide the following metrics:

- Estimated welfare effect on *all* market participants due to restructuring (the efficiency test). This metric would look at the overall net benefits and costs of restructuring, regardless of the identities of the participants that were the main beneficiaries of restructuring, and regardless of whether some participants were winners while others were losers.

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[311] See Appendix B for summaries of benefit-cost studies of RTOs.

- Estimated welfare effect on consumers due to market malfunction (the equity test). This metric would look at the net benefits and costs of restructuring to consumers only, ignoring impacts on (for example) generation firms and the environment.

Arguably, under our definition of ideal measurement of RTO benefits and costs, there has been no definitive study that measuring adequately the benefits and costs of organizing wholesale energy markets under the administration of an RTO; although there have been many studies conducted over the past several years that purport to show that the benefits exceed the costs.

8.1. PJM

To the extent that there are benefits that arise from these institutional changes, the review of the PJM RTO suggests that problems with generation and transmission investment incentives and lack of coordination, the lack of long-term transmission rights and the relatively minor role of demand response in the wholesale market limit the efficiency of the short-term market as well as the ability of the market to achieve greater efficiency over the long term.

Without the vantage point of examining the record of performance over an entire business cycle, it is difficult to say whether there are net benefits associated with restructuring wholesale markets and creating RTOs to administer them. To the extent that there are net benefits, it is even more difficult to say whether retail consumers are sharing in those benefits because of the complexity of retail rate structures, the general lag between changes in utility costs and changes in retail rates through rate cases, and the fact that, even in states that have initiated competition at the retail level, retail consumers in large numbers continue to take service under bundled retail service rate structures.

8.2. Midwest ISO

The Midwest ISO has estimated that its Day 2 energy market, by improving commitment and dispatch efficiencies, will yield "a potential annual gross savings of about $713 million to energy consumers."[312] Another cost-benefit analysis is reportedly underway that examines the first year of the Day 2 market operations.

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[312] Midwest ISO 2004 Annual Report, p. 4.

APPENDIX A.
BACKGROUND ON ELECTRIC INDUSTRY RESTRUCTURING

The Energy Policy Act of 1992 had the overarching public policy goal of promoting competition in wholesale power markets through open access to the transmission system. Following passage of the 1992 EPAct, FERC undertook a number of initiatives to support the creation of competitive wholesale markets. In particular, Order Nos. 888 and 889, issued in 1996, required transmission owners to provide access to their networks at cost-based prices, to end discriminatory practices against unaffiliated generators and marketers, to expand their transmission networks if they did not have the capacity to accommodate requests for transmission service, and to provide non-discriminatory access to information requested by third parties. In addition, in an attempt to advance non-discriminatory access to the transmission system, Order No. 888 promoted the voluntary formation of Independent System Operators (ISOs).

Concerned about the slow pace of progress under Order Nos. 888 and 889, FERC issued, in 1999, Order No. 2000, which contained a new set of regulations designed to facilitate the "voluntary" creation of large RTOs.[313] With Order No. 2000, FERC hoped to resolve problems created by the balkanized control of U.S. transmission networks and by the alleged discriminatory practices of transmission owners against independent generators, energy traders, and LSEs seeking transmission services. Order No. 2000 articulated several important goals for wholesale market institutions. The goals include: a) the creation of impartial transmission system operators who will operate transmission networks reliably and economically without being influenced by the financial interests of market participants; b) the creation of large regional transmission networks with common transmission access and pricing rules and with common wholesale market institutions that mitigate inefficiencies associated with the balkanized ownership and operation of transmission networks; and c) the creation of wholesale market institutions to support efficient power trades and efficient allocation of scarce transmission capacity.

In mid-2002, FERC commenced a new rulemaking proceeding to consider a proposal for a "Standard Market Design" (SMD) that would apply to all transmission-owning utilities over which FERC had jurisdiction. The proposed SMD rule enumerated a much more detailed set of wholesale market design requirements, including: a) Independent Transmission Providers (ITPs) who would assume operating responsibility for transmission systems; b) day-ahead and real-time wholesale energy markets with locational marginal pricing (LMP); c) resource adequacy requirements that would obligate all load-serving entities (LSEs) to make forward commitments for generating capacity and/or demand response to meet their forecast peak demand plus a reserve margin to be determined through a regional stakeholder process; d) regional transmission planning and expansion processes that would identify transmission investment needs for

[313] *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999). Order No. 2000 technically makes participation in an RTO voluntary, but FERC may employ carrots and sticks that create significant pressure for utilities to join RTOs. Order No. 2000 does not mandate a particular organizational form for an RTO, however.

interconnections, reliability requirements, and generation cost reductions; and e) market monitoring and market power mitigation mechanisms, including a $1,000 per MWh bid cap for energy and ancillary services in the day-ahead and real-time markets, as well as bidding restrictions to deal with local market power problems. Because of substantial opposition, FERC withdrew the SMD proposal in 2005.

As a result of FERC's "open access" Order Nos. 888 and 889, most transmission-owning utilities in the U.S. (either directly or through an ISO or RTO) offer transmission service with the following characteristics:

- standardized cost-based transmission service tariffs for the provision of transmission service;
- readily accessible real-time information about the availability and prices of transmission service on their networks;
- standard procedures for interconnecting independent power producers to their networks;
- an obligation to make best efforts to expand their transmission networks to meet transmission service requests when adequate transmission capacity is not available to accommodate these requests; and
- provision of certain network support services, including balancing services, to parties using their networks.

Transmission owners are required to adhere to rules that functionally separate their transmission network staffs from their generation and marketing staffs. This functional separation, together with the foregoing transmission service characteristics, is intended to support new entry of independent generators, expansions in wholesale trade, and retail competition.

Figure 52 summarizes graphically the geographic scope of RTO and ISO coverage of the nation's electrical grid and generation resources as of late 2005. Table 44 presents some key statistics about each of the RTOs.

Figure 52
ISO and RTO Configurations in the United States
2005[314]

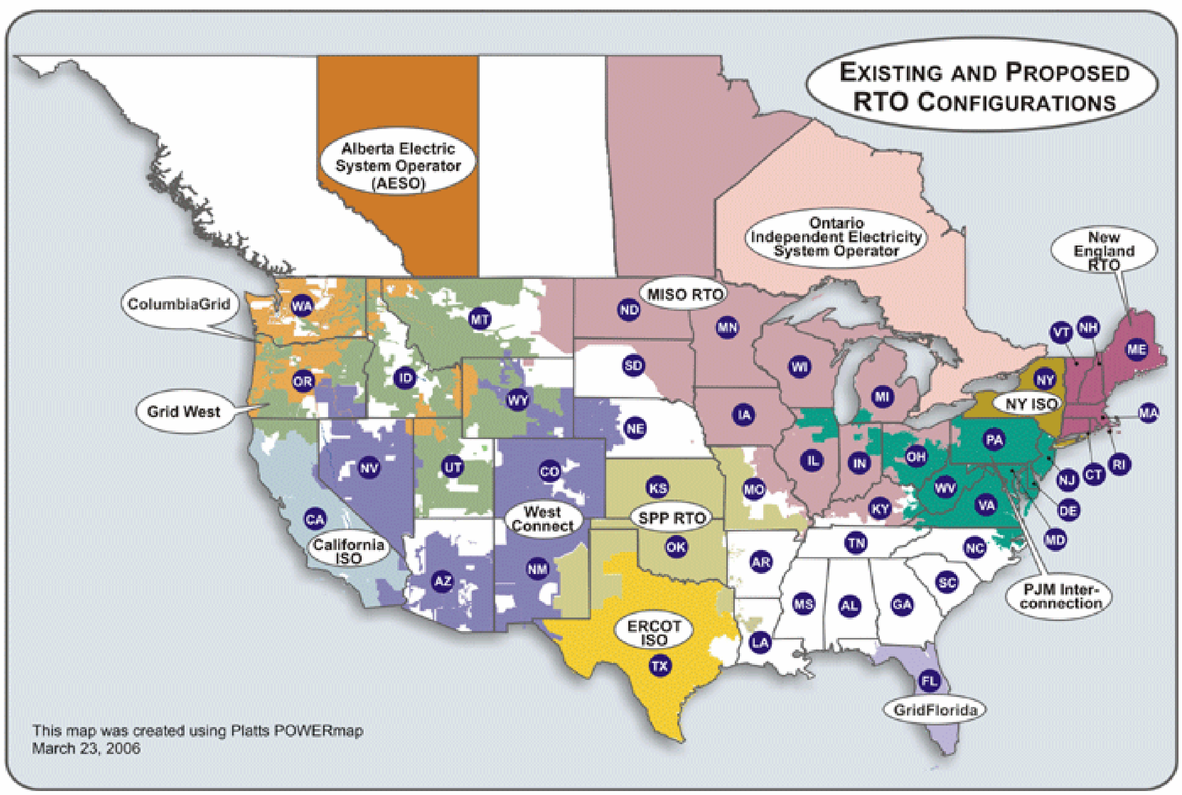

Table 44
RTO Characteristics[315]

	CAISO	ERCOT	ISO-NE	Midwest ISO	NYISO	PJM	SPP
Number of States	1	1	6	15 + Manitoba	1	13 + DC	6
Employees	500	500	400	600	400	600	130
Transmission (miles)	26,000	37,000	8,000	100,000	11,000	56,000	52,000
Generation (MW)	55,000	77,000	31,000	132,000	38,000	164,000	45,000
Peak Load (MW)	46,000	60,000	27,000	112,000	32,000	134,000	41,000
Energy Load (Annual TWh)	230	290	135	224[316]	160	700	192

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[314] Federal Energy Regulatory Commission, http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp, downloaded 3/30/06.

[315] From Barker, Dunn & Rossi, Inc. *Report on RTO Costs and Benefits for Electric Cooperatives*, prepared for the Power Supply Task Force of the Cooperative Research Network of the National Rural Electric Cooperative Association, October 5, 2005.

[316] Estimated.

Order No. 2000 has also led to significant changes in the electric industry. Table 45 indicates that, as of mid-2005, just over half of the generating capacity in the U.S. (including Texas which is not subject to FERC jurisdiction) is operating within an ISO/RTO context.

Table 45
ISOs and RTOs and Generating Capacity: 2005[317]

System Operator	Generating Capacity (MW)	Percent of U.S. Total
California ISO	58,000	6%
ERCOT (Texas)	74,000	7%
ISO-New England	31,000	3%
Midwest ISO	134,000	13%
New York ISO	39,000	4%
PJM	164,000	16%
Southwest Power Pool	61,000	6%
ISO/RTO TOTAL	561,000	56%
Total U.S. Generating Capacity	997,000	100%

Despite FERC's withdrawal of the controversial SMD proposal, Midwest ISO, ISO New England (ISO-NE), the New York Independent System Operator (NYISO), and PJM have adopted the basic wholesale market principles reflected in the SMD; the California Independent System Operator (CAISO) is in the process of adopting these principles; and the Electric Reliability Council of Texas (ERCOT) is giving these principles serious consideration. Among the ISOs and RTOs, only the Southwest Power Pool (SPP) is not moving toward an SMD-like market design. The SMD markets generally have day-ahead, hour-ahead, and real-time energy prices that are determined through uniform price auctions. Prices for energy reflect the marginal cost of congestion at each location on the network; and in New England, New York, and Midwest ISO they reflect the marginal cost of losses as well.[318] Locational prices adjust to changes in supply and demand conditions on the network consistent with changes in the network's physical constraints.

LMP prices implicitly induce a market-based allocation of scarce transmission capacity: the prices of congestion are transparent because they equal differences in locational spot energy

[317] California ISO, *2004 Annual Report*, http://www.caiso.com/docs/2005/07/20/2005072016553817629.pdf; Energy Information Administration, *Electric Power Monthly*, September 2005, http://www.eia.doe.gov/cneaf/electricity/epm/epmxlfilees3.xls; Electric Reliability Council of Texas, *ERCOT Winter Assessment*, http://www.ercot.com/meetings/tac/keydocs/2005/; ISO New England, *SCC Monthly Report*, December 2005.xls; Midwest Independent Transmission System Operator, *2004 Midwest ISO State of the Market Report 2004*, http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-7bf20a48324a?rev=1; New York Independent System Operator, http://www.nyiso.com/public/company/about_us/annual_report.jsp; PJM Interconnection, http://www.pjm.com/about/overview.html; and Southwest Power Pool, *SPP State of the Market Report 2004*, http://www.spp.org/Publications/SPP_State-of-the-Market-Report_05312005.pdf. Update for 2005 based on FERC, *Winter 2005-2006 Energy Market Update,* Item No. A-3, February 16, 2006, a presentation to the FERC Commissioners by Commission staff, obtained at http://www.ferc.gov/legal/staff-reports/eng-mkt-con.pdf.

[318] PJM intends, at some future date, to incorporate marginal losses into its LMPs.

prices. In theory, administrative rationing of scarce transmission capacity through the application of Transmission Loading Relief (TLR) rules should be unnecessary since transmission capacity would be rationed by prices and willingness to pay rather than through inefficient administrative curtailments. The practical realities of balancing supply and demand in real time, however, means that load curtailments are still used occasionally when locational prices are unable to achieve the desired rationing of transmission capacity.

To allow hedging against uncertain congestion prices, the RTO markets offer Financial Transmission Rights (FTRs) of up to one year's duration.[319] These FTRs provide their owners with revenues that approximately offset their liability for congestion charges between their resources and loads.

Although FERC could not and did not order vertically integrated utilities to divest either their generating facilities or their transmission facilities, the combination of state initiatives, regulatory incentives, and market opportunities has led to a considerable amount of restructuring of the ownership of existing generating plants.

In 1996, there were about 750,000 MW of electric generating capacity in the U.S., of which investor-owned utilities (IOUs) owned about 580,000 MW (77%). After 1996, about 100,000 MW of generating capacity were divested by IOUs and another 100,000 MW were transferred to unregulated utility affiliates to compete in the wholesale market. Moreover, between 1999 and 2005 about 200,000 MW of new generating capacity was completed, about 80% of which was owned by unregulated generating companies, including both independent power companies (IPPs) and unregulated "merchant" affiliates of utilities. Electric cooperatives added 11,535 MW of that new generating capacity, or about 5.8%.

More new generating capacity entered the market between 2001 and 2003 than in any three-year period in U.S. history.[320] The vast majority of this new generation capacity was in the form of natural gas-fired combined cycle (CC) plants and combustion turbines (CTs). Indeed, there was so much entry and so little exit that by 2003 there was excess generating capacity in most regions of the country. By 2004, over 40% of the power produced by investor-owned companies in the U.S. (i.e., excluding federal, state, municipal and cooperative generation) came from unregulated power plants, up from about 15% in 1996. IOUs' affiliated power producers produced a significant portion of this power. After a nearly two-year decline in market liquidity following Enron's collapse, trading in financial electricity products during 2004 increased by a factor of ten and increased again by almost that factor in 2005.[321]

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[319] FTRs have a variety of names, including fixed transmission rights and congestion revenue rights. Auction Revenue Rights (ARRs), which are rights to revenues from FTR auctions, also hedge against uncertain congestion prices. Except when the text specifically refers to ARRs, this report's references to "FTRs" may generally be understood to also include ARRs.

[320] Federal Energy Regulatory Commission, *2004 State of the Markets Report: An Assessment of the Energy Markets in the United States in 2004*, A Staff Report of the Office of Market Oversight and Investigations, June 2005, Docket No. MO05-4-000, p. 53 (hereinafter the "FERC 2004 SOM Report"), p. 59.

[321] *Ibid.*, p. 63.

APPENDIX B.
STUDIES OF RTO COSTS AND BENEFITS

This appendix provides synopses of cost-benefit studies that have been conducted in recent years by various organizations and consulting firms. Each study synopsis provides a summary of the general results and conclusions, a brief discussion of the methods and assumptions used and the limitations or shortcomings of the study.

B.1. Cambridge Energy Research Associates (CERA) Study: *Beyond the Crossroads: The Future Direction of Power Industry Restructuring*

The CERA Study claims that "US residential electric customers paid about $34 billion (in 1997 dollars) less for the electricity they consumed over the past seven years than they would have paid if traditional regulation had continued."[322] This estimate is based upon a comparison, over the period 1998-2004, of the actual values of the Urban Consumer Price Index of Electricity (CPIE) to "predicted" values of what retail electricity prices would have been if deregulation had not occurred. [323, 324] If the actual "deregulated" prices are less than the predicted "regulated" prices, then CERA finds a positive benefit of deregulation to residential customers; and if the actual "deregulated" prices are greater than the predicted "regulated" prices, then CERA finds a negative benefit (that is, a loss to residential customers). CERA estimates separate results for each of four U.S. regions: Northeast, South, Midwest, and West.

The validity of CERA's net benefit findings rests entirely on two assumptions: that markets in all four regions were "regulated" through 1997 and were "deregulated" after 1997; and that CERA's statistical model provides reasonable estimates of what retail electricity prices would have been if deregulation had not occurred. Both of these assumptions are plainly incorrect. Fatal flaws in the study that render it beyond belief include:

- Carelessness in distinguishing "regulated" market periods from "deregulated" market periods.
- Attribution of the lion's share ($24 billion) of deregulation benefits to the South region even though this region has seen very little deregulation.
- Attribution of a large share ($9 billion) to the Midwest region even though this region had no functioning ISO or RTO until 2002.

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[322] CERA Study, p. ES-1.

[323] The U.S. Bureau of Labor Statistics (BLS) develops data series for the CPIE. For index values for the period 1981 to 2004, see http://data.bls.gov/PDQ/outside.jsp?survey=cu. The four regions analyzed in the CERA Report correspond to the four census regions reported by the BLS.

[324] The CPIE is a measure of the average change over time in the prices paid by urban consumers for delivered electricity provided by their local utility.

- Counting the losses of generators during the recent "bust" portion of the business cycle as part of the benefits of "deregulation" for residential consumers, even though these losses are not sustainable over the course of a business cycle.
- Ignoring the restructuring administration costs that inevitably offset any efficiency benefits that might be passed on to residential consumers.
- An empirical analysis that focuses solely on retail electricity prices even though: a) the direct effects of deregulation are primarily on wholesale electricity prices; and b) continuing price regulation at the state level prevents direct links between retail and wholesale prices.
- A statistically biased model with imprecise predictions of "regulated" prices because the values of the independent predictor variables are dependent on and determined by the regulatory process. Consequently, the prediction equation mispredicts what "regulated" prices would have been after 1997.

CERA's analysis is so deeply flawed that the findings do not merit serious consideration. In particular, the CERA Study's estimated $34 billion net benefits is based on a price prediction model that does so bad a job of predicting prices that it says that most of the benefits of deregulation occur in a part of the country (the South) that has seen very little deregulation. Furthermore, the empirical analysis is so specious that it adds nothing to our understanding of what restructuring at the wholesale level has accomplished. For policy makers thirsty for analyses that offer real insights into which policy decisions are delivering benefits and which ones are not, the CERA Study is just another desert island.

B.2. Global Energy Decisions (GED) Study: *Putting Competitive Power Markets to the Test*

This Report, in its three sections, reaches three major sets of conclusions:

1. Over the 1999 – 2003 study period, "consumers in the Eastern Interconnection have realized a $15.1 billion benefit due to wholesale competition over what they would have realized under the traditional regulated utility environment."[325]
2. The "electric utility industry has improved its operations and efficiencies largely because of competitive forces."[326]
3. "[E]xpanding the PJM wholesale power market in 2004 produced $85.4 million in annualized production cost savings to wholesale customers in the Eastern Interconnection."[327]

The Report does not reveal clearly (or fails to reveal) all of the explicit or implicit assumptions that have been made to produce its results and conclusions. To evaluate the reasonableness of the estimated $15 billion benefit requires a thorough examination of the Report. A close

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[325] Report, p. 1-1.

[326] Report, p. 2-1.

[327] Report, p. 3-1.

examination reveals that the first set of conclusions is vacuous: GED's benefit estimate rests on clearly implausible assumptions that lead to a gross overstatement of benefits. When the results are corrected for these implausibilities, the estimated benefits evaporate to almost zero. Furthermore, when the ISO and RTO costs of running these competitive wholesale markets are taken into consideration, the estimated benefits become negative—consumers are worse off than before.

GED's definition of the hypothetical world without wholesale competition fails to distinguish market outcomes that require RTOs from those that can occur without RTOs. Specifically, in simulating the world without wholesale competition, GED assumes that there are "no competitive power plants, no regional transmission organizations, and wholesale energy is exchanged at marginal cost based contracts rather than wholesale market-based pricing."[328] Since past and present experience indicates that it is possible to have competitive power plants without having RTOs or, for that matter, even having open access at the retail level, the lion's share of the estimated benefits might be due to one part of the hypothetical (e.g., competitive power plants) but might be wrongly attributed to the whole package or the presence of the RTO. Thus, the Report does not separate the effects of the various elements of the hypothetical; nor does it, aside from the preceding quote, provide a detailed definition of what those various elements are. Consequently, even if the Report's claims of benefits were accurate, they don't provide policy makers with any guidance on how to proceed from here.

The second and third sets of conclusions appear to be based on more reasonable assumptions and some real evidence, though they are arguably highly optimistic and selectively overstate the case. In particular, the Report fails to make a careful but absolutely essential distinction among the efficiency effects of the many elements of competition and restructuring; and so it consequently adds nothing to our knowledge about or understanding of how structural and institutional reform has produced any benefits.

B.3. Center for the Advancement of Energy Markets: *Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region*

Most of the Study is devoted to general discussions of the history of electric utility regulation, the features of the PJM market, questions concerning optimal capacity and reserve markets, and the expected sources of benefits of power market restructuring. It identifies the following primary sources of potential benefits from power market restructuring:

- efficiency increases and corresponding cost reductions in the investment and operation of generation due to wholesale market competition (Section 4.1);
- consumer benefits and cost savings from the effects of price responsive demand (Section 4.2); and
- lower costs and increased consumer benefits from retail competition and product differentiation (Section 4.3).

[328] Report, p. 1-2.

By contrast, the Study's Executive Summary and CAEM's publicity concerning the Study are mostly dedicated to presenting the core quantitative results that appear in the Study's Section 5.3 and Section 5 Appendix.

Although other parts of the Study say that the primary source of potential restructuring benefits is the lower *costs* brought about by increased competition, the quantitative estimates of restructuring are based on changes in *retail prices* over time. The Study justifies this approach by claiming "Much of the benefit from current restructuring is captured by reduced prices to ultimate customers."[329]

The Study recognizes that "Constructing reliable estimates of these benefits requires estimating the change in prices to customers due specifically to restructuring, and not due to other factors."[330] It notes that changes in retail electricity prices in a restructured region may occur due to a number of possible factors, including the following:

- changes in wholesale costs or prices due to external factors such as changes in fuel costs or to production efficiencies brought on by restructuring;
- changes in allowed recovery of stranded costs; and
- the nature of regulated retail rates negotiated by utilities and regulators as part of a restructuring process.

The Study further points out that the challenge of calculating the cost-saving benefits due to restructuring requires isolating that portion of any observed retail price changes that may be attributed directly to restructuring.[331]

But instead of unraveling the relative importance of these factors in contributing to recent reductions in retail prices in the PJM area, the Study simply compares the reduction in inflation-adjusted retail electricity prices between 1997 and 2002 in the states within the PJM area to the corresponding reduction in retail electricity prices in three neighboring states; and from this comparison it infers the portion of reduced electricity expenditures in PJM that are due to restructuring rather than from other causes. The Study then assumes that these reduced expenditures will continue into the indefinite future and that the eventual expiration of stranded cost recovery will be an additional benefit of restructuring; and it discounts these benefits back to the present to produce its $28.7 billion estimate of the benefits of restructuring in the PJM area.

Furthermore, the Study never makes clear what it means by its use of the term restructuring. In the Study, the term is used broadly to refer to anything and everything that has taken place in the PJM region to both the wholesale and retail electric markets during the period 1997 to 2002. But restructuring of the retail and wholesale electric markets represent two parallel, yet complementary reform movements underway in the electricity sector in the 1990s. They should be separated sufficiently in order for a discussion of these events and any analysis of their impacts to be comprehensible. The restructuring of the retail markets involved one set of

[329] Study at pp. 42-43.

[330] Study at p. 46.

[331] Study at p. 43, states "[t]he task of capturing the benefits of restructuring requires isolating the price increment (ΔP) produced by restructuring."

activities while the restructuring of the wholesale markets entailed another set of events and activities.

B.4. Synapse Energy Economics, Inc.: *Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs*

Synapse Energy Economics (Synapse) prepared a study of the PJM electricity markets in an attempt to understand rate trends for electric generation within the PJM Interconnection (PJM) region, specifically to examine the effect of restructuring on prices. Synapse estimates and compares two sets of annual prices: (1) the actual wholesale power costs (WPC) in the PJM market, and (2) prices in a scenario with economic regulation continued from the mid-1990s to today so that the generation service costs (GSC) are the unbundled generation portion of the pre-deregulation cost-of-service rates. Synapse examined three companies in the region: Delmarva Power & Light in Delaware (Delmarva), Jersey Central Power & Light in New Jersey (JPCL), and the Pennsylvania Electric Company in Pennsylvania (Penelec).

The study included all years since the beginning of PJM market operation—1999 through 2003. To understand the impact of wholesale market restructuring on retail rates, Synapse unbundled the pre-deregulation prices using primary information from the three companies' FERC Form 1s. Synapse accounted for changes in system parameters, such as the cost of fuels, by developing an "index" for GSC, that enabled Synapse to project those GSC from 1996 through 2003, under an assumption that regulation continued over the period 1999 to 2003 just as it had been applied prior to that time period. Many assumptions were required in order to accomplish this projection of GSC. Synapse does a good job of explaining all of the assumptions that were made to produce the counterfactual prediction, and caveats the results obtained with words of caution about the limitations of empirical analysis of this sort.

Synapse found that, while PJM deregulated wholesale market GSC fluctuate year-to-year, on average, the actual wholesale power costs over the five year period 1999 to 2003 are lower than the projected GSCs based on the constructed index. This conclusion is, however, subject to at least five important caveats that Synapse itself clearly acknowledges.

1. While the Synapse approach is reasonable, data limitations required the use of highly simplified assumptions about trends in capital costs, taxes, and other factors. The projected indexed GSC costs may overestimate regulated GSC because they include all the "stranded costs" that were collected in transition charges and, likely, some portion of stranded costs that were not collected, and they also do not include mandated retail rate reductions, productivity improvements in utility-owned generation or reductions in the overhead costs of operations.
2. The actual wholesale power costs were calculated without any explicit incorporation of transmission costs, something that might readily be done now based upon the results of PJM's recent auction of transmission rights.
3. The actual wholesale power costs are calculated strictly generation costs in the PJM wholesale markets and do not include some factors that may be in the actual prices that customers are paying at the retail level such as "retail adders" for marketing costs, perceived risks to suppliers, and prices above competitive market prices due the exercise of market power.

4. The WPCs over the past few years have been lower than were previously expected as a result of capacity surpluses from the significant addition of new generating plants in the PJM region, a situation that customers will not enjoy indefinitely.
5. Synapse examined only three utilities. It is quite possible that analysis of other companies in PJM would show different results.

APPENDIX C.
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