Impacts of the PJM RTO Market Expansion

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A REPORT PREPARED FOR PJM BY

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I. Executive Summary

The purpose of this report is to review the impact of PJM's expansion on PJM itself and on the electric markets of new PJM service areas in Ohio, Kentucky, Virginia, West Virginia, Illinois, Indiana and Michigan. This review is based on the understanding that what has been imposed on the electric industry since 1992 is *not* deregulation, but *changes* in regulations. The purpose of these changes has been to insert the competitive struggle into the power business. We take as a given that this is generally seen as a desirable objective because competition is a stimulus to improvements of all kinds: "As one business introduces a better or a cheaper product, others are forced to do the same. Indeed, the existence of competition will lead each business independently to make improvements, since a firm which merely matches the advances made by others runs the risk of being left behind. The contribution of this competitive process to the development of the American economic system is generally understood…"[1]

There have been a number of other studies on the topic of the effects of imposing a PJM-style market, and in an effort to avoid duplication, this study focuses on several areas that have not been extensively reviewed in these other evaluations[2]. Generally speaking, it is widely understood and accepted that consumers in one region in the integrated market can save money by importing power from the rest of PJM, replacing power that had formerly been obtained at a higher price. These are classical "gains from trade" that underpin economic unions.

It is also generally understood that the failure to develop adequate regulations for competitive markets can result in the exercise of market power, to the detriment of consumers. It is assumed in this report that PJM and its regulators will continue to be vigilant against the exercise of market power.

In the case of electricity, gains should be expected from creating and enlarging a competitive market because the larger market allows a more diverse set of generation and transmission assets to be optimized. The PJM market design generally establishes useful parameters for energy, capacity, and transmission service pricing, and for the interconnection requests that are at the center of maintaining reliability in the face of strong demand growth. Where those parameters are found wanting – capacity market design, for example – PJM takes it upon itself to gather information and conduct stakeholder hearings

[1] R.H. Coase, "The Theory of Public Utility Pricing and its Application," 1 *Bell Journal of Economics* 113 (1970), p. 125.

[2] *Problems in the Organized Market* (Washington, D.C.: Electricity Consumers Resource Council, April 2005). *Competition Works in Electric Power Markets: a 2004 Update* (Washington, D.C.: Electric Power Supply Association, 2004). *Putting Competitive Power Markets to the Test*, (Sacramento, CA: Global Energy Decisions, 2005), among others.

about the inadequacy, and then makes its own independent judgment about the appropriate market design changes to propose to its regulators.

One measure of the gain of establishing and then enlarging an electricity market is to measure the difference in energy prices with and without the larger market. For example, PJM has estimated the gains for Allegheny Energy consumers at $99 million for an eight-month study period, which amounts to over $2/MWh.[3]

ESAI has conducted a similar assessment for the new market areas, *but as the starting point*, rather than the end-point, of our analysis of the impact of PJM on the new market areas. Our technical study assessed the weighted average energy price for the broader PJM region with and without integration. This analysis indicates that the region-wide energy price without integration would be $0.78/MWh higher in 2005 than with integration. Spreading these savings over the total PJM RTO's energy demand of 700 terawatt-hours (TWh) per year yields aggregate savings of over $500 million per year. (see Section 5).

This conclusion forms the basis for a review of more subtle, and ultimately more important consequences of establishing a larger electric market. We conclude that the five most important impacts of the expansion of PJM are:

1. **PJM's role as the *agent for change* in the electric business expands to a larger area and will affect more consumers:** (see Section II) PJM is responsible for introducing a series of innovations in its new western and southern power markets, the most prominent of which are:

    - Pricing conventions and price transparency for electricity products (electric energy, capacity/reliability services, and other ancillary services);

    - Rules for new asset interconnection that invite new entrants with innovative ideas to invest in the system at their own risk;

    - Open and potentially innovative rights to the use of the transmission system.

2. **PJM is expanding an electric forward market that has no bias:** (see Section III) so that buyers and sellers can hedge their exposures with confidence.

    - Over an extended period of time, the forward price in an unbiased market should bear no systematic relationship, other than 0, with the spot price. This is a rigorous test. In the energy arena, only the very successful crude oil and natural gas futures markets exhibit this lack of bias. ESAI has conducted

[3] "Evaluation of the Increase in the Economic Efficiency of the Overall PJM Unit Commitment and Economic Dispatch Resulting from the Integration of Allegheny Power into the PJM Energy Market", Andrew Ott, PJM, December 2002.

bias tests for the forward energy market and we conclude that the PJM Western Hub bias is relatively small and has been improving.

- In addition, we have found that the size of the bid-ask spread in PJM's forward markets has been diminishing. These indications are primarily in the shorter-term contract areas, but over time should extend to the longer-dated contracts as well. This is a key measure of market liquidity and has a direct impact on reducing transaction costs for both buyers and sellers.

- ESAI has also conducted bias tests for several regional markers to determine if PJM financial transmission rights (FTRs) constitute effective hedging mechanisms. We have found that there is no systematic bias and that FTRs are an effective hedging mechanism.

- On the basis of this analysis, ESAI concludes that PJM is a market in which short-term risks (defined as two years or less) can be effectively hedged.

- PJM and its newly integrated markets have another property that is of substantial, albeit under-appreciated value: a diversified portfolio of generation assets. As the price of natural gas has increased in recent years, the value of that diversification has become more apparent.

- The value of a market in which risks can be effectively hedged, in which the bid-ask spreads are small, and in which there is a diverse portfolio of power generating facilities is extremely high. ESAI conservatively asserts that favorable increases in the liquidity and diversity of PJM's market will yield aggregate savings to electricity consumers of $1-2/MWh, amounting to $0.7 to 1.4 billion per year.

3. **PJM has developed and will extend an effective *reliability* and *capacity* set of protocols:** (see Section IV) We define this as establishing a set of economic incentives – preferably in a competitive marketplace – that motivate investments in <u>*generation*</u>, <u>*transmission*</u>, and <u>*demand management*</u> assets that collectively constitute the resources of the power market.

   - At first glance, the PJM Installed Capacity (ICAP) Market would appear to have satisfied this definition, as more than 100,000 MW of interconnection requests were filed with PJM from 1999 to 2003. Many of those requests, however, were made during a period now seen as "irrationally exuberant" with regards to generation. In the last three years, the number of substantial generation interconnection requests (in PJM and all other U.S. electric markets) has collapsed for reasons we review in this study. It is widely believed – in PJM and elsewhere – that the peculiarities of electric markets make the current ICAP market design inappropriate.

- In the summer of 2005, PJM submitted a substantial redesign of its capacity market (called the "Reliability Pricing Model," or RPM) to the Federal Energy Regulatory Commission. We describe the RPM in this report and explain that by reducing the volatility of capacity revenues (which have often been negligible under the existing protocols), RPM will stimulate substantial investment in PJM.

- In the absence of a functioning capacity construct, energy prices will rise sharply and the cumulative effects of these increases will be quite substantial, amounting to at least $500 million up to $5 billion each year should reserve levels fall significantly.

4. **PJM has developed and will extend an *efficient energy market*:** (see Section V) An efficient market should be defined as one in which the "competitive struggle" is constantly present. Efficiency can be measured in a number of ways. Measures of the efficiency of the manufacture of electricity, such as the market heat rate, should shows signs of the competitive struggle.

   - PJM's market meets that test, as the average on-peak heat rate has declined from 9,000 to 7,300 Btu/kwh from 2001 to 2004.

   - As already noted, our technical study assessed the weighted average energy price for the broader PJM region with and without integration and found annual energy market savings of over $500 million per year due to the optimization effects of centrally dispatched operations.

   - Most importantly, PJM is the home of the premier electric index in the industry. Its liquidity is better than that of any other market, and is improving more rapidly than that of any other market.

5. **PJM's expansion stimulates substantial *increases in electric trade*.** (see Section VI) Our analysis indicates that:

   - Import/export trade has increased significantly as expected with the larger borders. This in itself is significant for PJM due to the increased diversity of supplies and market opportunities. The reduction of seams costs with MISO has only served to further the scope of trade increases.

- The focus of ESAI's study has been to investigate the changes in flows over what were formerly external interfaces that have now become internalized. We have found that:

    - Flows between Allegheny Power and PJM Classic, over the previously defined external interface, have increased by 10-15 percent per year on average since integration in 2002.

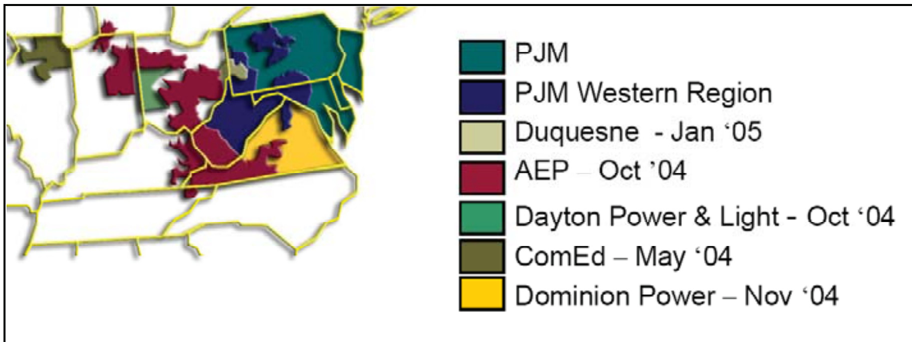
    - Flows over the former PJM West (AP) interface with American Electric Power (AEP) have shifted dramatically higher post-integration, October 2004. We believe that this is a reflection of the increased dispatch efficiency within the new RTO area.

    - The corresponding flow study from First Energy to PJM West pre and post integration did not show any change in flows. We believe that this difference in the changes in flows from the integrated and non-integrated areas (AEP vs. FE) is noteworthy

    - Dominion entered the PJM RTO in May 2005. Subsequently, net export flows from PJM to Dominion in May and June have increased by 1,000 MW compared with the first four months of 2005. This change in flows directly reflects optimization of the Dominion system under RTO operations.

Finally, the expansion of a market into previously regulated areas should increase the "innovation efficiency" within the market area (see Section VII). On the basis of American experience with regulation, it is a given that industries where market forces subject participants to the competitive struggle spawn more innovation than industries where market forces are absent. We review a large array of innovations that PJM has already introduced into the electric industry.

As observed with the airlines and telecommunications industries, the effect of these innovations takes time to materialize. Over time, however, their effect snowballs and brings permanent enhancements to consumer welfare. We have also learned from these other industries that restructuring of major industries is the work, not of a few years, but of a generation. By that standard, after 10 years of introducing competition to electric markets, the development and impacts of innovations in the PJM marketplace are still in the early stages.



PJM RTO - SUMMARY OF KEY STATISTICS - 1998-2005

	Original Footprint	*PJM Merges With:*				
PJM STATISTICS	**PJM Classic**	**Allegheny Power**	**ComEd**	**AEP & Dayton**	**Duquesne**	**Dominion**
DATE OF PJM MARKET ENTRY	1998 Basis	Apr 1, 2002	May 1, 2004	Oct 1, 2004	Jan 1, 2005	May 1, 2005
PEOPLE SERVED, millions	22	25	35	44	45.3	51
PEAK LOAD, megawatts	49,400	61,200	87,000	107,400	110,700	131,300
GENERATING CAPACITY, megawatts*	56,000	67,000	106,000	134,000	137,500	163,800
TRANSMISSION LINES, miles	14,500	20,000	25,000	49,300	49,970	56,070
NUMBER OF GENERATORS	600	660	800	984	1,001	1,082
TERRITORY, square miles	48,700	79,000	91,000	137,700	138,510	164,260
AREA SERVED, no. of states	5 + D.C.	7 + D.C.	8 + D.C.	12 + D.C.	12 + D.C.	13 + D.C.

* - RTO capacity on integration date

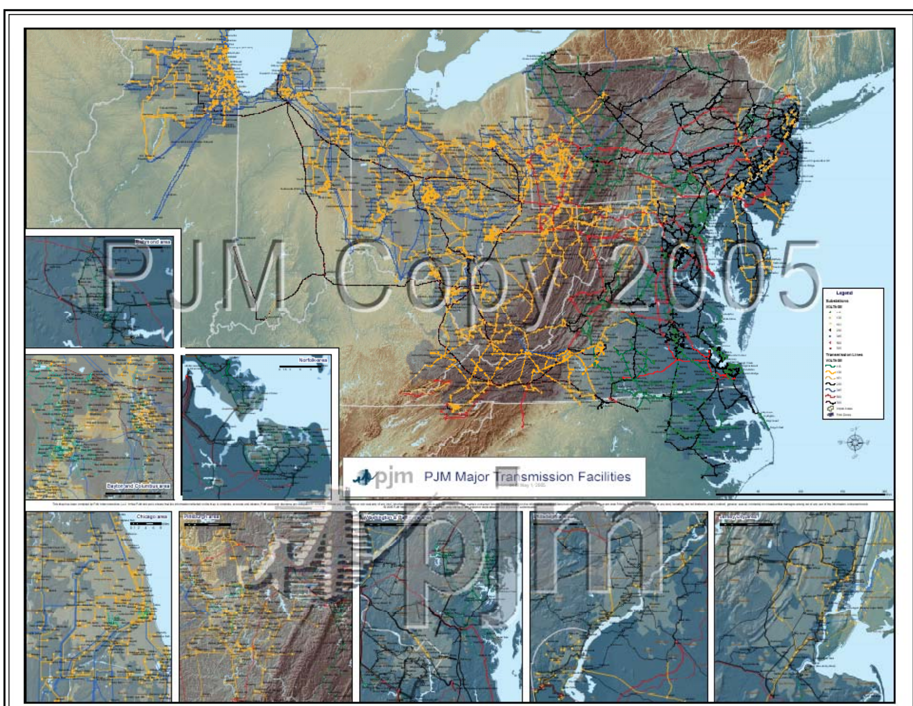
II. Introduction

The PJM electric market has expanded from its original footprint encompassing Pennsylvania, New Jersey, Maryland, Delaware, Virginia and District of Columbia electric markets to a much larger area including additional markets from Virginia, West Virginia, Kentucky, Ohio, Indiana, Illinois, and Michigan. PJM now oversees the transmission grids of an area that encompasses 5.6 percent of the territory of the lower 48 states but consumes 17.5 percent of the total power generated. It is the largest power market in the world.

Moreover, PJM is the only power market created since the seminal Federal Energy Policy Act of 1992 and the subsequent Order 888 of the Federal Energy Regulatory Commission (FERC) that has expanded so substantially from its initial core membership. When PJM admits new members like American Electric Power, Dayton Power and Light, Commonwealth Edison and Virginia Electric, the areas served by these utilities become part and parcel of a market designed to promote wholesale market competition in an industry that had been comprehensively regulated since 1935.

As a result, it is expected that competition within the framework of PJM rules and regulations will induce changes that will, in aggregate, convey substantial benefits to the consumers of electricity in these areas. Those benefits will be defined in terms of economic efficiency, innovations in product offerings, and increases in the breadth of choices that consumers have in how they purchase electricity services in the market.

Figure 1



Seen in this way, PJM is an *agent for change* in the electric business in the areas where its rules and regulations are imposed. The primary changes it introduces are in:

1. **The market rules** that PJM applies to the purchase and sale of electricity products (electric energy, capacity/reliability services, and other ancillary services),

2. **The interconnection rules** that PJM applies to enterprises seeking to do business in the PJM area, and

3. **The transmission system management, pricing and expansion process** that PJM manages on behalf of its stakeholders and in response to guidance from its regulators.

Before developing this taxonomy further, however, it is important to review the purposes of restructuring.

The Purposes of Restructuring

Electricity restructuring in the United States began, as do most major changes in our economic life, with ideas. Among them was dissatisfaction with the regulatory *status quo* that had governed the power sector since 1935, new support for the power and efficiency of market forces that manifest themselves in the administrations of Ronald Reagan and Margaret Thatcher, and a growing awareness of energy issues thanks to the oil crises of 1973 and 1979.[4]

[4] The US Congressional Research Service summarizes electric utility regulation and restructuring as follows. "The foundation of federal regulation of electric utilities is the Public Utilities Holding Company Act of 1935 (PUHCA) and the Federal Power Act (FPA). These laws were enacted to eliminate unfair practices and other abuses by electricity and gas holding companies by requiring federal control in regulation of interstate public utility holding companies. Prior to PUHCA, electricity holding companies were characterized as having excessive consumer rates, high debt-to-equity ratios, and unreliable service. Under PUHCA, the Securities and Exchange Commission (SEC) regulates mergers and diversification proposals of holding companies whose subsidiaries engage in retail electricity or natural gas distribution. In addition, PUHCA required that before purchasing securities or property from another company, a holding company be required to file for approval with the SEC. The SEC could exempt a utility from PUHCA if its business operations and those of its subsidiaries occurred within one state or contiguous states. The first federal step in restructuring was the Public Utility Regulatory Policies Act of 1978 (PURPA), P.L. 95-617. PURPA was, in part, intended to augment electric utility generation with more efficiently produced electricity and to provide equitable rates to electric consumers. Utilities are required to buy all power produced by qualifying facilities (QFs) at avoided cost. QFs are exempt from regulation under PUHCA and the FPA. Electricity regulation was changed again in 1992 with the passage of the Energy Policy Act (EPACT), P.L. 102-486. The intent of Title 7 of EPACT was to increase competition in the electric generating sector by creating new entities called "exempt wholesale generators" (EWGs), that can generate and sell electricity at wholesale without being regulated as utilities under PUHCA. This title also provided EWGs with a way to assure transmission (wheeling) of their wholesale power to its purchasers. In response to EPACT, on April 24, 1996, the Federal Energy Regula-

As an influential review of regulation concluded in 1970, "the basic problem [with electricity regulation] seems to be not a lack of high quality leadership in the regulatory commissions… but rather that the *methods* of regulation themselves cause inefficient operations in the public utility industries."[5] This perspective from 1970 is a useful reminder that what has been imposed on the electric industry since 1992 is not deregulation, but ***changes in regulations***. PJM is part of an effort, not to deregulate electric markets, but to effect changes in electric regulations that are more conducive to bringing competition into the electric power industry for the sake of inducing more "efficient operations."

A variety of restructuring ideas – chief among them allowing non-utility companies to generate electricity, granting those companies equal and open access to the transmission grid, and promoting market-based electricity pricing -- were embraced by elected officials in the federal government and in many state governments, and were enacted into key pieces of federal and state legislation. That legislation gave regulators a mandate to change how property rights were defined in U.S. wholesale electric systems. The ability to acquire these rights allowed newcomers to connect to transmission grids that had been built over preceding decades by the regulated industry.

In the process, firms in the electric business were given an opportunity to retain utility status, or to charge market-based rates for their products. The typical electric firm changed from its identity as exclusively a utility to a more complex organization with a more complex appetite for risks and innovations. In addition, some brand-new types of firms entered the electric business: some specialized in building independent generation capacity (AES, Calpine), others in trading (Enron), and yet others bridged what appeared to be a natural connection between ownership of natural gas pipelines and trading in the electric markets (Williams, Dynegy, El Paso).

Even before the formal restructuring began, small pockets of power market activity had naturally cropped up as utilities – in an electric version of the primitive exchange of nuts and fruits at the edge of a forest – sought to sell their surplus power or buy power more economically from their neighbors. Occasionally, small electric connections were made to facilitate these trades. In a few cases, control over large hydroelectric facilities and support from federal and state programs enabled very large, long distance transmission projects to be built. These became very important in parts of the United States and Canada, and established precedents for determining the rules of the game for the reliable sale of power between neighboring jurisdictions.

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tory Commission (FERC) issued two final rules to encourage wholesale competition (Orders 888 and 889). FERC believed these rules on transmission access would remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to competitive bulk power markets." Taken from http://www.ncseonline.org/NLE/CRSreports/briefingbooks/electricity/ebeledes.cfm.

[5] Paul MacAvoy, *The Crisis of the Regulatory Commissions,* (New York, WW Norton and Co., 1970), p. viii.

In this manner, power markets evolved, establishing a historic record for wholesale prices for energy-only and firm energy (which reflected a commitment to maintain generating capacity in good working order for reliability purposes). Some of these prices had varying degrees of forwardness to them, reflecting a commitment to commit capital over time. Even before restructuring, therefore, there were forward energy-only and firm energy markets and prices.

As these early power markets evolved, it was natural for participants to pose certain questions such as;

- What constitutes a high-quality market?
- How can depth and liquidity be enhanced? (Concepts long understood and enshrined in other marketplaces).
- How is a portfolio of electric market positions structured? (Another concept of long standing from other markets), and
- How is unacceptable market power assessed?

Over time, the actions of both newcomers and the more market-oriented utilities rubbed against the incumbent traditional utilities. This resulted in the establishment of a body of state and federal regulations as well as case law. Gradually, the initial restructuring legislation was further fleshed out by a mosaic of new electric tariffs and legal precedents as the inevitable litigation over differing interpretations of the original enabling legislation ran its course.

In short, electric restructuring originated with an idea – following in the footsteps of other industries previously deregulated and restructured. This idea was expressed in legislation and regulatory changes, which then exerted itself in a process of change-producing transformations in company structures and operations, market designs, and the regulatory landscape.

The Work of a Generation

This electric restructuring process began in the 1980s. Building up an electric industry that created power grids granting widespread access to electricity was the work of those now called the Greatest Generation. Restructuring the industry has been the work of their successors, the Baby Boomers, who also restructured other businesses – finance, transportation and communication most prominently among them. Restructuring in these fundamental sectors has profoundly changed companies, markets, and laws in those sectors of the economy.

The keys to understanding electric restructuring, therefore, are (1) that, as the work of a generation, it is still in its early years, and any appraisal of progress (or lack thereof) thus far must take that into account, and (2) that any thorough understanding of restructuring's consequences for a state, regional or national economy must be tracked in terms of its effects on the firm, the market, and the law.[6]

Restructuring effects will be most profound where the original incumbent firms are thoroughly transformed. By that measure, both the airline and the communications industries have been thoroughly restructured. Familiar and historic firms like Bankers Trust, AT&T and Pan American Airways have been taken over, diminished or liquidated.

Where restructuring takes hold, markets also become more complex, product selection and innovation are expected to increase, and participants should develop new capabilities to structure forward transactions. It is readily apparent that how people buy airline, communications, and financial services is completely different than it was a generation ago. Restructuring has allowed market participants to introduce a large array of new products and services at a rate that appears to exceed the rate at which innovations occurred during the regulated era. One of the measures of restructuring effects, therefore, is the pace at which market participants introduce new services and products.

In businesses where there is a need for forward transactions – mortgages, interest rates, exchange rates -- the restructuring and deregulation of financial services over the last two decades has led to the emergence of significant new futures, forward, and over the counter markets. The function of these forward markets is to enable efficient hedging for those who do not want to carry forward mortgage, interest rate, or exchange rate risks. For individual consumers, today's wide array of mortgage services would be impossible without the large array of financial forward and futures markets behind it.

Finally, no introduction to restructuring and its long-term effects would be complete without referring to the paradox that was pointed out by R.H. Coase decades ago: *that some of the most successful markets in well-functioning economies are quite heavily regulated*. He pointed to futures markets as an example.

The Idea

Coase's paradox reminds us that ***the point of restructuring is not the elimination of regulation;*** the point of restructuring is the elimination of monopolies or oligopolies that tend to emerge in all economies over the course of decades. And so it was with electricity, where the long-term domination of the "utility" as the paradigm for how to organize a firm in this sector lost its appeal to many – but by no means all – of the state and federal regulators of the industry. Put another way, the purpose of restructuring is to implant the competitive struggle into the power business because:

[6]Those familiar with the work of the Nobel prize winning economist, R.H. Coase, will see references in this introduction to several of Coase's most prominent themes, including the title of one of his major works, *The Firm, The Market, and the Law* (University of Chicago Press, 1988).

> "The competitive struggle in business, as elsewhere, is a stimulus to improvements of all kinds. One business introduces a better or a cheaper product, and others are forced to do the same. Indeed, the existence of competition will lead each business independently to make improvements, since a firm which merely matches the advance made by others runs the risk of being left behind. The contribution of this competitive process to the development of the American economic system is generally understood…"[7]

For many observers of the power sector, this is enough. For others, however, "The purpose of restructuring the electric utility industry is to promote economic efficiency, not simply to create competitive markets."[8] The Congressional Research Service goes on to say that "Competitive markets are a vehicle to increase economic efficiency by relating costs and prices. Proponents argue that the events of the last 15-20 years demonstrate that the regulatory system has not provided consumers with the proper price signal regarding the current relationship between costs and prices. Restructuring those segments of the electric system that can sustain viable competitive markets would at least partially restore the necessary price signal to consumers and suppliers."

In this respect, we have learned from other restructuring efforts that economic efficiency is not the only type of efficiency. We have learned from telecommunications restructuring that the "criteria for long-term economic efficiency embody both dynamic and static efficiency. Static efficiency stands for minimized costs of current production both at the firm level and at the industry level. On the other hand, dynamic (innovative) efficiency reflects demand creation and innovation. Innovation not only improves quality and variety, but also leads to price reductions by the invention of cost-reducing new technologies… dynamic efficiency provides the greatest improvement in social welfare." [9]

Therefore, in electric systems that join PJM we are looking for these changes in economic efficiencies. To understand what such changes look like, we have to briefly review PJM's various sets of rules. In the pages that follow, we describe PJM in terms of its market rules, its interconnection rules, and its transmission rules.

PJM Market Rules

The first of the three major changes that PJM participation creates for wholesale participants in new market areas is a change in *market rules.* This

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[7] R.H. Coase, "The Theory of Public Utility Pricing and its Application," 1 Bell Journal of Economics 113 (1970), p. 125.

[8] Congressional Research Service, http://www.ncseonline.org/NLE/CRSreports/briefingbooks/ electricity/ebeledes.cfm.

[9] Marc Bourreau and Pınar Doğan "Regulation and Innovation in the Telecommunications Industry: *Forthcoming Telecommunications Policy, Pre-publication version" presented in* **http://www.enst.fr.**

change transforms the electric pricing process from one in which utilities are allowed to charge customers based largely on service area aggregate production costs to one in which prices are determined by supply and demand in an organized market.[10] PJM's pricing platform consists of two major components:

1. ***The electric energy market:*** PJM has developed a platform in which energy is traded in day-ahead and "real-time" increments at each node of its system (distribution bus, substation, or generator bus). Offers to buy and sell at each node yield an array of "locational marginal prices" (LMPs) that reflects the state of the market at that node (barring the exercise of market power).

2. ***The capacity/reliability market:*** The electricity business is distinctive in its need to enforce a margin of spare manufacturing capacity to ensure that the power grid can meet the demand and prevent a blackout. The size of this required reserve (Installed Reserve Margin) varies by market; in PJM it is currently 15 percent. The obligation to procure this capacity falls on PJM's "load-serving entities" which are typically electric distribution utilities, and, more recently, deregulated retail service providers. PJM administers a "capacity market" in which the demand for capacity from these entities is combined with generation (or substitutes for generation) from suppliers.

   In contrast to the energy market, whose basic rules are now familiar and accepted by market participants, the rules governing the capacity/reliability market are still in flux. In the summer of 2005, PJM proposed to FERC a substantial revision in the rules, which it called the "Reliability Pricing Model" (RPM).

PJM Interconnection Rules

The second of the three major changes that PJM participation produces for new market areas is a change in *interconnection rules*. The basic principle of federal electricity policy is *open access* to the interstate transmission system. Generally, utilities' rights to exercise control over grid use have been curbed by the principle that, since they earn regulated profits by virtue of their status as public utilities, they must allow other qualified entities to interconnect to the transmission system. Because this system has a one hundred year legacy of intricate construction, there must be carefully crafted standards such that the interconnection of new facilities does not degrade the reliability of the system. Further, new interconnections should not unfairly deprive incumbents of rights within that system to which they have become accustomed.

[10] The analytical foundation for trading electricity in spot and forward markets was developed by Fred C. Schweppe, Michael C. Caramanis, Richard D. Tabors, Roger E. Bohn, *Spot Pricing of Electricity*, (Boston, Kluwer Academic Publishers, 1988)

Membership in PJM provides new market areas with a substantially developed body of interconnection regulations. As with other aspects of new competitive electric markets, this is an area that continues to evolve. Much of the interest and activity in designing PJM's super-area interconnection regulation has been in developing sound practices for distinguishing between "firm" and "non-firm" transmission services. From an interconnection standpoint, a "firm" service entitles a new resource to inject into (in the case of generators or transmission projects into PJM from other areas), or withdraw from (in the case of transmission projects that move capacity from PJM to other markets) PJM's array of resources that are deemed to provide reserve capacity services. A non-firm service only entitles a new resource to inject energy into or withdraw energy from PJM.

PJM Transmission Management Rules

The third of the three major changes that PJM participation produces for new market areas is a change in the direct *management of the transmission system itself*. This entails pricing transmission services, continuously assessing the level of new transmission investment needed to maintain the requisite level of reliability in the system, developing an ongoing region-wide transmission expansion plan, and determining how to pay for expansion of the transmission system. Each of these has different manifestations at the PJM regional level than it has at a utility level.

1. Membership in PJM entails a transition from a single utility's *transmission pricing* regime to the PJM regime. By definition, the PJM footprint is larger than that of any of its member utilities. PJM's very purpose is to optimize the use of that expanded transmission grid. In principle, a utility should be able to join PJM and receive a similar level of transmission revenues as it did before joining. In return, the access to PJM's larger grid will enable that utility's customers the ability to buy and sell electricity in the much larger PJM market area, usually at approximately the same transmission service charge that they were traditionally paying their utility.

   Within this general transmission pricing principle, PJM defines (subject to approval from its regulators) who is entitled to "network service" (that is, the ability to transmit energy and capacity services from any two points in the system at the uniform "network transmission service charge") and defines what constitutes firm and non-firm service. PJM also determines whether and for how long the regional system can deliver firm services, such as firm "point to point" services desired by counter parties seeking to engage in particular bilateral transactions.

2. Membership in PJM also expands the geographic area in which the *reliability* of the electric service is examined and maintained. Instead of reliability being the sole responsibility of the traditional, incumbent utility, it now becomes the responsibility of the utility *and* PJM as well

as the regional councils of the North American Electricity Reliability Council.[11]

3. PJM undertakes a continuous Regional Transmission Expansion Plan (RTEP) in order to maintain the reliability of the transmission system over time given load growth, generation retirements and additions, and independently developed changes in the transmission system. Membership in PJM entails participation in this process.

4. Transmission expansion occurs in PJM either for reliability reasons or for economic reasons. Reliability-motivated expansions are rate-based and incorporated into the network service charge (each customer that is part of PJM native load pays this charge regardless of location). Merchant transmission projects (like the recently initiated Neptune High Voltage Direct Current project between Sayreville, N.J. and Long Island) are financed by the project's participants. PJM has designed its rules so that economic projects in the AC system could also be funded by those who want them.

Criteria for Assessing PJM's Impact

This three-part taxonomy of market rules, interconnection rules and transmission management rules describes the broad areas in which PJM directly impacts the activities of market participants and ultimately, the economic well-being of end-use customers. ESAI has conducted an assessment of the impacts of PJM's ground-breaking efforts in electric market design and implementation, particularly as it relates to the benefits of incorporating new service territories into its RTO footprint.

This assessment has been conducted through studies of market price and volume trends as well as studies of shifts in energy transfers between PJM and the merged areas pre- and post-integration. ESAI also assesses the impacts of capacity market design on generation and transmission investment and the potential impact on energy prices. In addition, ESAI has undertaken detailed powerflow modeling to quantify the value of centrally dispatching all areas of the enlarged RTO footprint as compared to a disaggregated dispatch.

The rest of this report is organized into the following sections:

III. Liquidity and Diversity of PJM

Successful markets depend upon a diversity of interests from market par-

[11] MAAC, the Mid-Atlantic Area Council is one of ten reliability councils that form NERC, the North American Reliability Council. The purpose of these Councils is to ensure the adequacy, reliability and security of the bulk electric supply systems of the Region through coordinated operations and planning of their generation and transmission facilities.

ticipants and facilitate the development of tools, that promote a high level of trading activity. Good markets ultimately develop depth and liquidity, not only in their spot transactions, but also in their forward transactions. ESAI has developed an assessment of the effectiveness of the PJM markets by analyzing trends in the following areas:

1. Short term market volumes – The Day-Ahead Market of PJM has become the leading power market in the world in terms of volume and liquidity.

2. Longer-dated market volumes – month-ahead, quarterly, and calendar year trading is recovering.

3. Bid/Ask spreads – a high spread between market buy and sell orders indicates low liquidity and high transaction costs. A decrease in the bid/ask spread over time indicates an increase in the liquidity of the market and lower transaction costs.

4. Market bias – efficient markets show little or no bias in price over the long term. ESAI analyzes market bias for short and longer term markets as well as for selected FTR contracts.

IV. Reliability Effects of Integration: PJM Capacity Markets

The interactive dynamics of capacity and energy markets have an impact on the investment climate of the RTO and ultimately, on the reliability and security of the system. A system that does not attract investment capital to meet demand growth and to keep up with the requirements of maintaining a complex infrastructure will eventually run into difficulty meeting reliability expectations.

ESAI explores the current status of PJM capacity markets and the reliability outlook under the current paradigm, considered by many to be ineffective. Thus, capacity market reform is on the front burner in PJM as well as in other markets such as in New England and California. ESAI provides an overview of PJM's proposed Reliability Pricing Model, RPM, along with an analysis of the effects of RPM on both the energy markets and the investment climate. Looking ahead, ESAI addresses the question – "Will investors invest if the RPM is in place?"

V. Energy Price Effects of Integration

As new areas have been added to the PJM marketplace, each area brings its own array of generation which then becomes a part of the overall PJM generation portfolio. As each new service territory is integrated into the RTO, one would expect to see changes in price that would reflect changes in generation dispatch and inter-area transfers.

1. *Dispatch Benefits: Pre- & Post-Integration* - This study includes an assessment of the benefits of centrally dispatching the full expanded

PJM RTO through the use of a security constrained dispatch transmission power flow model. The dispatch conditions and resulting power prices of the full RTO central dispatch are determined. The results are then compared with the separate dispatch of PJM Classic and each of the individual merged areas on a disaggregated basis.

2. *Price Trends in PJM and Associated Markets* - On-peak and off-peak prices are examined for trends in relative value between PJM and other nearby market areas. Also, changes in volatility patterns are also indicative of changes in market conditions. Lower price volatility will usually increase market confidence - typically yielding greater market participation and deeper liquidity.

3. *Heat Rate Trends* - Given that electricity is largely a manufactured product, most of it coming from the combustion of coal, oil, and gas resources, each of which is a volatile commodity in its own right, the price of electricity alone is not a useful indicator of the effects of restructuring.

    - In technical terms, a generator's heat rate is a measure of its efficiency. A generator that can produce one kw of electricity using 7,000 Btus is more efficient than one that requires 12,000 Btu's to produce the same kw of energy. The efficient unit has a 'heat rate' of 7,000 Btu/kw. If the fuel price is $5.00/MMBtu, then the energy production cost of the more efficient unit is $35/MWh.

    - In the marketplace, the heat rate is an economic term for the normalization of energy prices using the natural gas price. To normalize the energy price, it is divided by the natural gas price. In the technical terms above, this is equivalent to the heat rate. However, the market price is not specific to the production cost of any particular unit, but rather is a function of the marginal costs or clearing prices that set the price in each time period. These normalized market clearing prices for energy are referred to as the 'market heat rate' or 'implied heat rate'.

    - The heat rate analysis provides a way to assess changes in the efficiency of the market as a whole, in particular, by removing the volatility associated with wildly fluctuating natural gas prices.

4. *Management of Regional Price Risks - FTRs* - The physical limits of the transmission system dictate that energy cannot flow freely under all conditions from one part of the system to another. Too much 'traffic' on the system will cause congestion. Much of the congestion experienced in PJM is due to well known system constraints such as the total flow limits that apply to the internal interfaces.

Congestion also occurs quite often as a result of changes in flow patterns that result from transmission outages or generator outages. In particular, an outage at a very large generator such as a nuclear power plant can cause significant changes in flow patterns. The combination of internal constraints and the wild card of forced outages determine differences in the cost of inter-zonal energy transfers.

- Financial Transmission Rights, FTRs, are the mechanism offered by the PJM market to hedge the pricing risks associated with transferring power from one location to another. FTRs are financial contracts which provide the owner with congestion revenues if the price difference between the source and sink points in his contract exceeds his purchase price.

- ESAI has measured the effectiveness of selected FTR contracts for hedging congestion price exposures through a bias evaluation. A low bias indicates that the contract is an efficient hedging mechanism by providing equal chances for gains or losses over time – i.e., net zero financial results on pure hedging activities.

<u>VI. Electric Trade Effects Of Integration</u>

The expansion of the PJM RTO will change power transfers between newly merged areaS and the original PJM prior to integration. ESAI/PJM flow data allowING comparisonS of metered flows across the appropriate interfaces show clear increases in trade as a result of optimized dispatch and the removal of trade constraints across the larger PJM market area.

<u>VII. Innovation Efficiency</u>

PJM has become the engine of innovation in its design and implementation of power markets. In what is evolving to be a hybrid market-regulatory regime, PJM continuously spawns innovations in its pursuit of becoming an effective platform for competitive power markets - within the bounds of reliability requirements, existing regulations and regional and federal politics.

The Integration of New Markets into PJM West

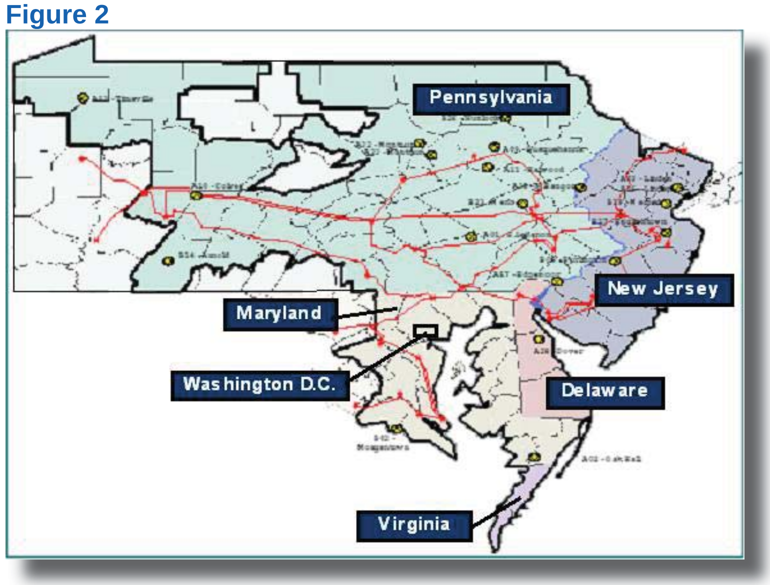
The original PJM market had a footprint defined in the chart below encompassing five states - Pennsylvania, New Jersey, Maryland, Delaware, and Virginia - as well as the District of Columbia. At the outset of PJM operations in 1998, the market had 56,000 MW of generation capacity, a peak load of 49,400 MW, 14,500 miles of transmission lines, and covered a population of 22 million. When Allegheny Power joined PJM on April 1, 2002, the RTO grew by 60 generating plants, and 10,000 MW of generating capacity.

In less than three years, PJM more than doubled in size from 67,000 MW of generation capacity to 164,000 MW. In May 2004, Commonwealth Edison, serving markets in Illinois, joined PJM adding 130 generators with 26,000 MW of capacity. In October 2004, the market areas served by American Electric Power and Dayton Power & Light joined (AEP, 130 generating plants and

32,000 MW of capacity – DPL, 45 power plants and 4,800 MW). In January 2005, Duquesne added 14 power plants and 3,000 MW and in May 2005 Dominion added 115 power plants and another 21,000 MW of capacity.

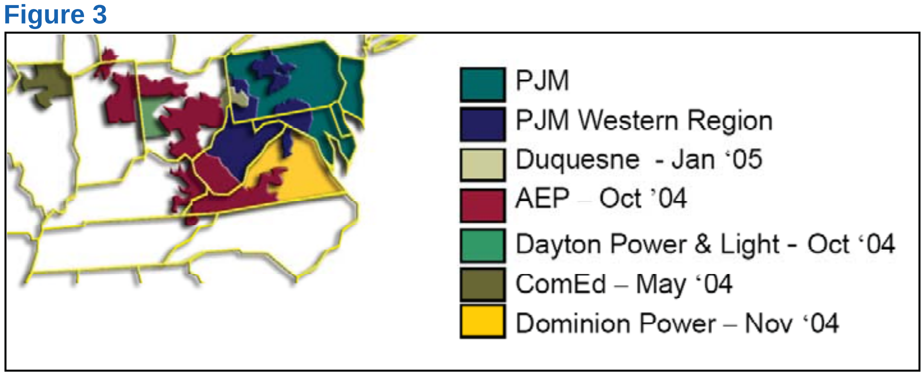
With these additions, the PJM market now encompasses 1,100 generating units, 164,000 MW of generation capacity, a 2005 peak load of 134,000 MW, more than 55,000 miles of transmission lines, and serves a population of more than 50 million. The footprint, as seen in the chart below, now extends far into the Midwest and the South, making PJM the largest power market in the world.

Figure 2



The impact of the expansion of PJM on the market, the firms, and the laws and regulations governing the wholesale electricity market can be reviewed from a variety of perspectives. We begin in the next section with an assessment of the depth, liquidity, and diversity of the new PJM.

Figure 3



PJM RTO - SUMMARY OF KEY STATISTICS - 1998-2005						
	Original Footprint	PJM Merges With:				
PJM STATISTICS	PJM Classic	Allegheny Power	ComEd	AEP & Dayton	Duquesne	Dominion
DATE OF PJM MARKET ENTRY	1998 Basis	Apr 1, 2002	May 1, 2004	Oct 1, 2004	Jan 1, 2005	May 1, 2005
PEOPLE SERVED, millions	22	25	35	44	45.3	51
PEAK LOAD, megawatts	49,400	61,200	87,000	107,400	110,700	131,300
GENERATING CAPACITY*, megawatts	56,000	67,000	106,000	134,000	137,500	163,800
TRANSMISSION LINES, miles	14,500	20,000	25,000	49,300	49,970	56,070
NUMBER OF GENERATORS	600	660	800	984	1,001	1,082
TERRITORY, square miles	48,700	79,000	91,000	137,700	138,510	164,260
AREA SERVED, no. of states	5 + D.C.	7 + D.C.	8 + D.C.	12 + D.C.	12 + D.C.	13 + D.C.

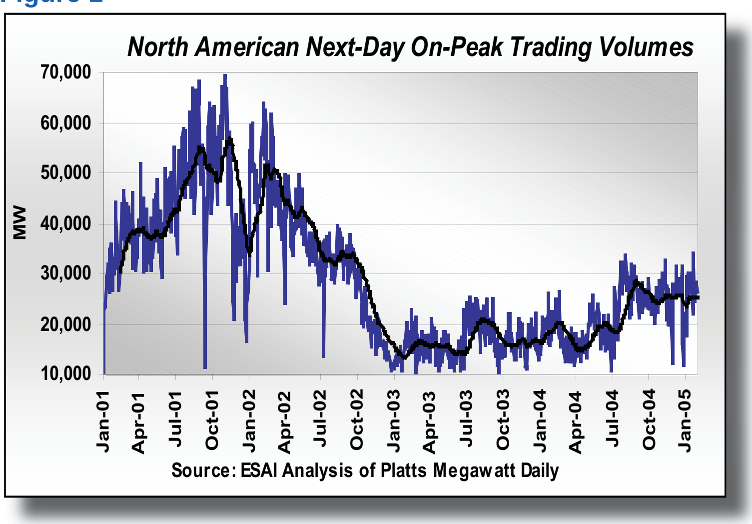
* - RTO capacity on integration date

III. Liquidity and Diversity of PJM

By their nature, competitive markets create their own demand for risk-management mechanisms. Every market has participants whose willingness to take market risk varies, and successful markets provide platforms that facilitate the development of tools – usually in the form of forward and futures markets – that enable a diversity of behaviors, from the most conservative to the most speculative.

Since the launch of the competitive market in 1998, liquidity in all North American power contracts, including PJM's, has undergone a pronounced rise, fall, and recovery. The demise of energy-trading companies in late 2001 and 2002 meant the withdrawal of many key providers of market liquidity and the disappearance of the main trading partners for many smaller firms – both on the web and via traditional trading avenues. The widespread contract defaults shook confidence in the reliability of electricity contracts and more importantly – it shook confidence in the integrity of the financial ratings of the companies actively involved in trading power contracts.

Figure 1



Before that occurred, however, optimism about the future of electric markets stimulated an enormous increase in the development and construction of merchant, project-financed power plants. Most of these plants were combined-cycle, natural gas-fired turbines. Between 1995 and 2002, approximately 200,000 MW of capacity was added to the national electric grid. For a variety of reasons, this increase in new capacity did not lead to a corresponding decrease in old generating capacity, and thus the value of generation collapsed. Many merchant generation companies – some of them already buffeted by the after-effects of the Enron and California affairs – succumbed to bankruptcy.

These events created an enormous withdrawal of capital from the power-trading sector, from which liquidity in the power markets, including PJM, has yet to fully recover.

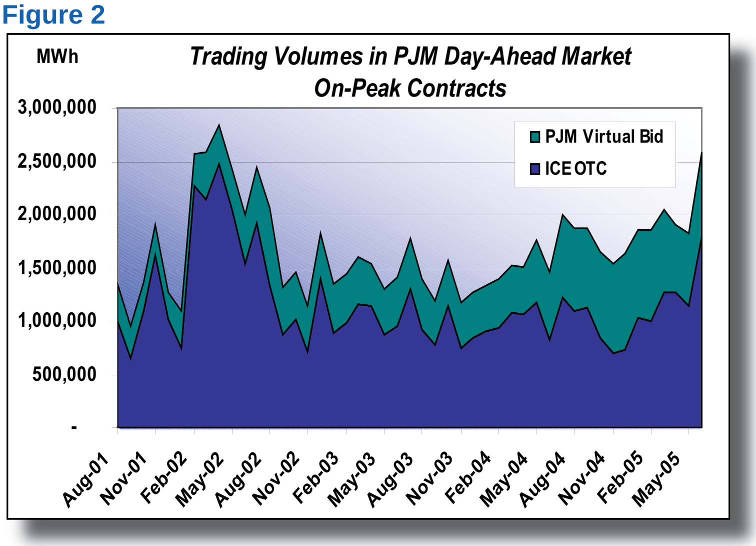
Since the nadir was reached in 2003, however, liquidity in the various types of contracts that constitute a healthy market has been gradually increasing. As of mid 2005, the greatest liquidity exists in short-term markets (day-ahead, weekly, and near month), and diminishes sharply in the longer-dated markets (next quarter, next year, subsequent years). Liquidity is generally better in market areas that have been established for years, specifically, PJM, New England and New York (in that order), than it is in non-market areas.[1]

Daily Market Volumes in PJM

PJM provides platforms for buying and selling energy products in a day-ahead market (with each hour traded separately), a real-time (or balancing) market (where smaller increments of time are bought or sold as needed to balance supply and demand on a minute-to-minute basis). These PJM-administered transactions are physical in nature, reflecting real commitments to inject or withdraw energy at each of PJM's nodes. To give market participants a chance to re-trade their day-ahead positions, PJM also established a virtual market that settles purely on financial terms with the real-time market.

In addition to these PJM-administered markets, the industry has also developed a series of over-the-counter markets for PJM's day-ahead contracts. Some of the entities that engage in these trades have collectively set up a trading platform called the Intercontinental Exchange (ICE). The PJM and other day-ahead market contracts represent the bulk of the volume of electric energy trading on ICE.

Figure 2



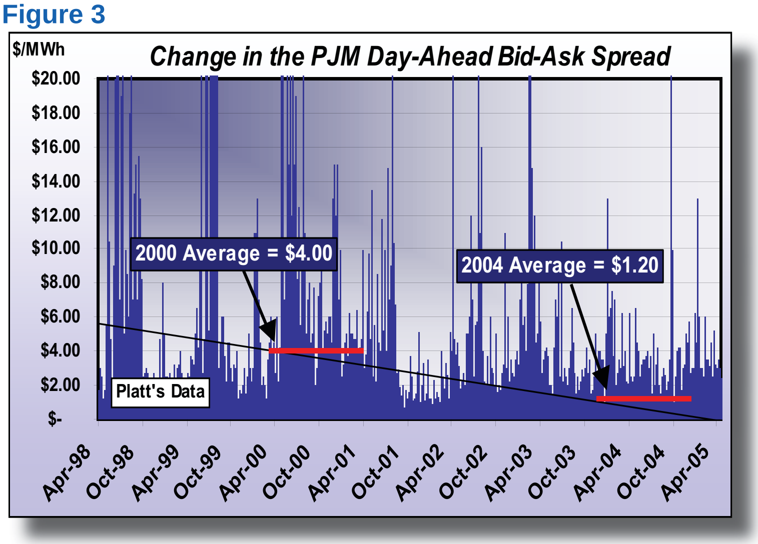
[1] Data was sourced from Megawatt Daily for the Day Ahead Market results and from the Intercontinental Exchange (ICE) for calendar year instruments.

Figure 2 shows the rise and fall and recovery of PJM's short-dated trading instruments. The volumes of the traded contracts peaked in late 2002 (much of this activity was related to unwinding Enron's positions) and began a substantial recovery in 2004. By the middle of 2005, PJM's day-ahead and real time markets (including the virtual bidding market) had volumes equaling those of the peak 2002 year.

The Bid-Ask Spread

Another measure of the improved liquidity of the PJM market is in the decline in the bid-ask spread. In illiquid markets, traders must maintain large spreads to protect themselves from large short-term losses on their inventory of contracts, thus an order at a price close to that of the previous transaction is unlikely to cover the spread, and hence unlikely to be executed. As liquidity improves, the trader's concern about holding positions he cannot get out of quickly diminishes and the spread generally declines.

Figure 3



Both major forward market databases (Platt's and ICE) indicate a reduction in the PJM day-ahead market bid-ask spread[2] as shown in the trend-line in Figure 3. Lower bid-ask spreads indicate lower risks, lower profits for market makers, and lower transaction costs. The increased confidence that results also increases the depth of market volumes traded, allowing greater size of individual trades as well as increased overall volumes.

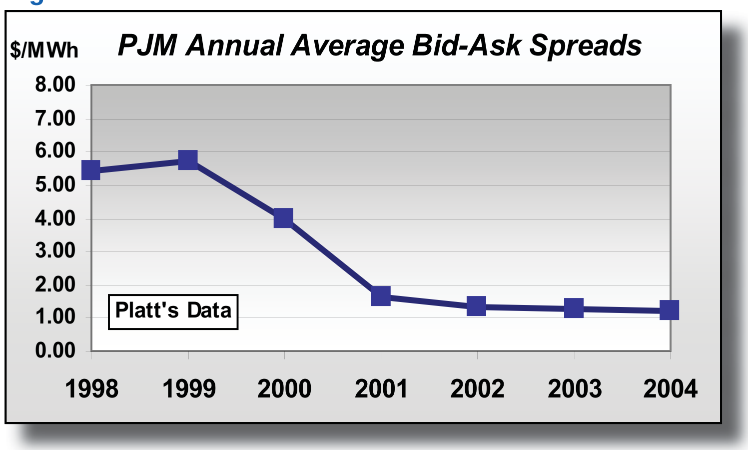
The bid-ask spreads have decreased from over $5.00/MWh in 1998-99 to $4.00 in 2000 and then to below $2.00 from 2001 onwards. This decrease translates to markedly lower transaction costs for market participants. Since the transaction cost of a forward transaction is generally defined as one half of the spread between the bid and the ask, plus commission costs, it can be

[2]The chart is based on Platt's database of PJM day-ahead, on and off peak transactions. The data do not present bid and ask information for each trade. Instead, it provides an Absolute Low, an Absolute High, and a volume weighted average price. We infer that the Absolute Low is a low bid, and the Absolute High is a high offer.

readily seen that the transaction costs in 2004 at $2.00 have dropped to below $1.00/MWh. While it is difficult to ascertain the volumes committed on behalf end-use customers through marketers and LSEs, the $1.00/MWh transaction cost savings is highly noteworthy. If only 50 percent of buying for end-users was transacted in the forward and over-the-counter markets such as ICE, the transaction cost savings would translate into annual savings of over $300 million.

Trading volumes in liquid markets typically exceed the underlying physical volumes by multiples. Therefore, the savings to traders and market participants from the lower transaction costs associated with greater liquidity can be much greater than the $300 million set forth above.

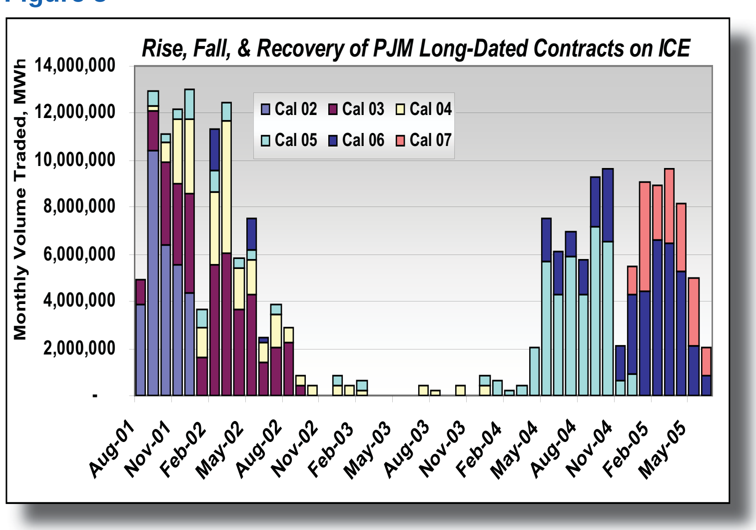
Figure 4



Calendar Year Market Volumes

Trading in calendar year strips (a one year contract for a specified volume) peaked in 2002 and 2003 with cumulative volumes trading on the Intercontinental Exchange exceeding over 50,000,000 MWh. As shown in Figure 5, calendar-year contract volumes declined sharply in 2003 and early 2004. They began to increase in 2004, as new financial players entered the energy-trading arena, and by the beginning of 2005 trading volumes for these long-dated contracts had increased to levels not seen since the trading heyday of 2002.

Figure 5



These increases bode well for PJM customers' ability to hedge part of their positions in quarter-ahead and year ahead derivative markets. While the increase in day ahead and virtual trading is also a welcome sign of liquidity, there must also be increases in longer-dated contract volumes if PJM customers are to get the full benefit of the development of competitive markets.

Effects of Liquidity: A Non-Biased Forward Market

Ideally, where forward markets exist and have adequate liquidity, they will have no particular bias in the relationship between the forward price and what the market spot price turns out to be. For short periods of time, of course, forward markets are likely to turn out to have a bias. For example, on November 3, 2003, a consumer could have locked in the price of natural gas for November 2004 at $4.81 on the New York Mercantile Exchange. The spot price of natural gas in November 2004 turned out to be $6.13. In this case, the 12th-month futures market price was $1.32 lower for November 2004 than the spot price turned out to be. Over longer periods of time, this bias should be close to zero in efficient markets.

We can take such measurements for all of the different contract periods (one month in the future, two months, one year, two years, etc) and thereby develop a measure of the *structural bias*, if any, of a given forward market. The extent to which there is such a bias in forward markets has been of interest to specialists and scholars for decades.[3] Generally speaking and over a long period of time, forward and futures markets should *not* be "good forecasters" of future spot prices – they should be wrong most of the time (as Figure 6 indicates is the case for natural gas). To think otherwise would be to naively attribute some sort of information or transactional advantage to operators in the forward markets. In today's hyper-efficient trading markets, such anomalies occur regularly, but they are quickly discovered by other traders and thereby disappear.

Figures 6 and 7 show the application of this principle to the robust and liquid U.S. Henry Hub natural gas futures contract traded on the New York Mercantile Exchange. It indicates that during the period January 1998 to the present, neither the first nor the twelfth month contract exhibited a bias.

Such results require mature and liquid markets. Indeed, in the early stages of the natural gas markets there were periods when the forward markets were not as efficient as they are today. The same can be expected from power markets, especially when one bears in mind that – unlike natural gas – electric markets are unlikely to be able to develop a single, *national* benchmark as

[3] See, for example, Charles Engel, "The Forward Discount Anomaly and the Risk Premium: A Survey of Recent Evidence," 3 *Journal of Empirical Finance* (1996), pp. 123 – 192.

Figure 6

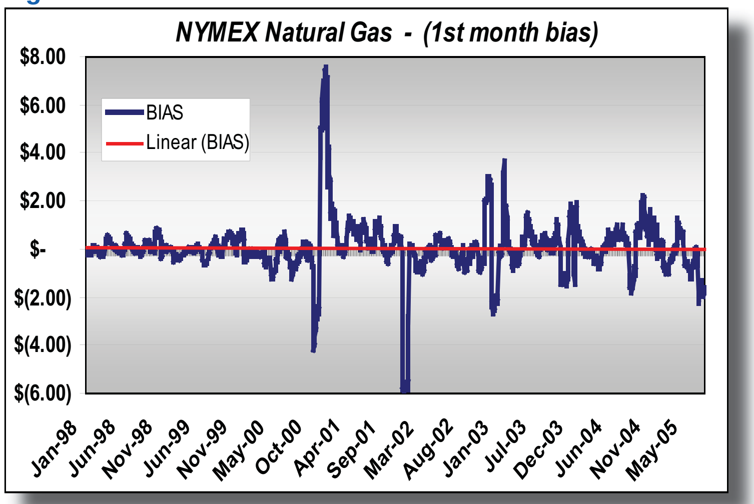
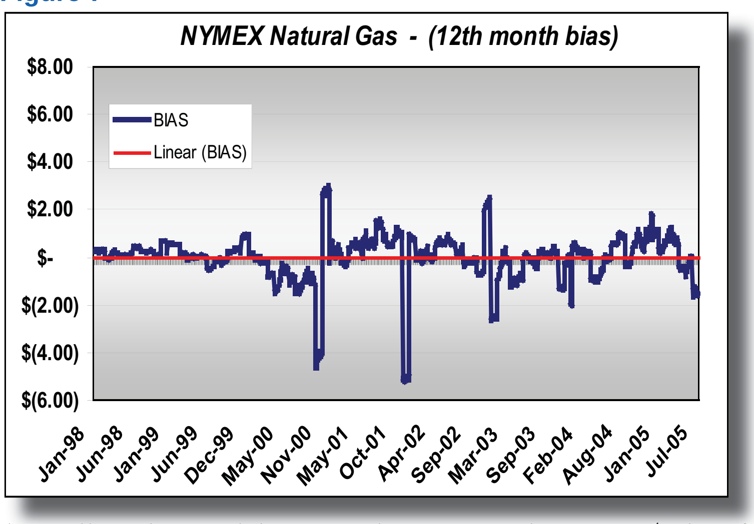


Figure 7



acceptable to all market participants as the Henry Hub contract.[4] Therefore, it would be premature to expect similarly unbiased results for the PJM market. We should, nevertheless, do the analysis to determine where the PJM market is in the desired evolution towards an unbiased market.

PJM Bias

Forward power price bias has to be carefully defined and measured. We must acknowledge from the outset that PJM's installed capacity (ICAP) market is not ready for this kind of test, for reasons explained later in this report.

[4] The Henry Hub is a spot trading area in Louisiana through which a substantial amount of US and imported natural gas flows. Moreover, natural gas has a national distribution network (albeit the west coast is not as well-integrated with that network as the east and the Midwest), and thus the price of the commodity at the Louisiana Hub is meaningful for all market participants. Electric markets trade much more regionally; hence PJM West has become the most meaningful index for the greater PJM market.

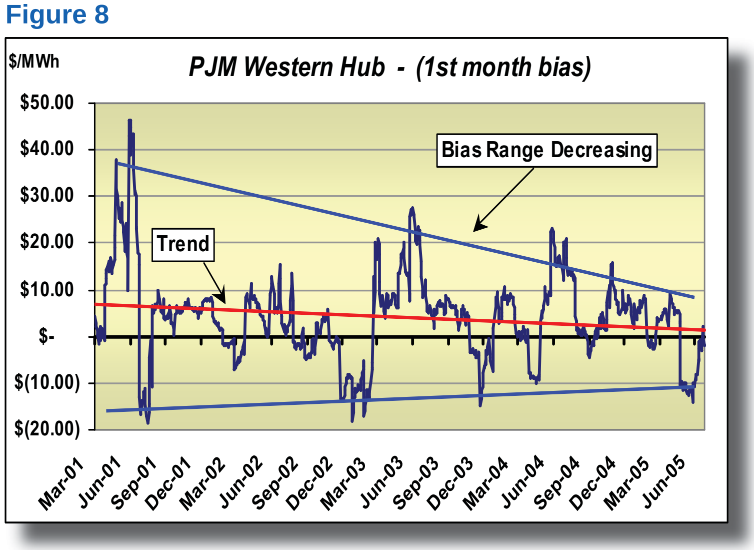
We can examine, however, the energy market and evaluate bias in its contracts and we will do so in two different ways. First, we can analyze the bias in energy price contracts and second, we can analyze the bias in FTR contracts (Financial Transmission Rights).

The energy price in PJM is a complex amalgamation of commodity input fuels costs (with natural gas-fired units often setting prices in the peak hours, and coal-fired units setting prices in the off-peak hours). We have already determined that, over the very long run, natural gas prices are unbiased. To the extent that on-peak power prices are biased, we can attribute the bias to market participants' expectations of the heat rate (rather than their expectations of the input fuel price).

One other caveat needs to be mentioned before we proceed. The natural gas futures market is conveniently arrayed into years of monthly forward contracts. Thus, traders routinely transact a December or a February contract, one or two or three years into the future (although liquidity does decline further out in time). In the power market, different trading "packages" have arisen which make it inconvenient to analyze a "twelfth month" in as straightforward a fashion as can be done in the natural gas contract. We have, therefore, concentrated our analysis on the PJM West "next month" and "3rd month" contracts.

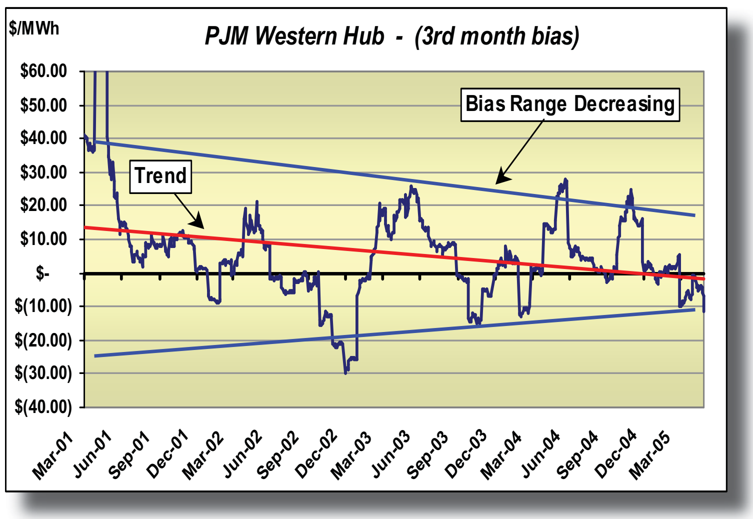
In the first month contract, the early years of PJM Western Hub trading exhibited a propensity for the forward market to price peak energy at higher levels than actual spot market (DAM) results. In 2001 (March to December), the one-month forward price averaged $9/MWh higher than the spot price. In calendar year 2002, the one-month forward price averaged $0.20/MWh *lower* than the spot price. In 2003, the one-month forward price averaged $6/MWh higher than the spot price. In 2004, the one-month forward price averaged $5/MWh higher than the spot price. In 2005 (through the end of June) the one-month forward price averaged $0.30/MWh lower than the spot price. For the entire market period, the one-month bias averaged $4/MWh and, as seen in the chart above, a trend line through the individual (daily) bias figures shows a strong trend toward a smaller bias.

Figure 8



In the third month contract, the early years of PJM Western Hub trading exhibited the same propensity for the forward market to price peak energy at higher levels than the spot market turned out to have. In 2001 (March to December) the third-month forward price averaged $19/MWh higher than the spot price. In calendar year 2002, the third-month forward price averaged $4/MWh *lower* than the spot price. In 2003, the third-month forward price averaged $6/MWh higher than the spot price. In 2004, the third-month forward price averaged $7/MWh higher than the spot price. In 2005 (through the end of June) the one-month forward price averaged $2/MWh lower than the spot price. For the entire market period, as with the month-ahead market, the third month contract bias averaged $5.84/MWh and the trend line through the individual (daily) bias figures again shows a strong trend toward a smaller bias.

Figure 9



As the PJM power markets mature and become more efficient, we anticipate a more systemic lack of bias in the relationship between forward and spot prices. The forward markets will be – as they should be – poor forecasters for future prices but good platforms for hedging and managing risk exposures.

FTR Hedging Effectiveness and Bias

In the same way that we would expect the PJM Western Hub contract to show minimal bias, it would be ideal if each of the basis markets similarly showed little or no bias. This is a challenging standard because there are thousands of potential nodal/zonal pricing relationships in the expanded PJM, and therefore the liquidity of these mini-markets is bound to be less substantial than it is for the PJM Western Hub index.

Nevertheless, we studied the market bias for two FTR contracts – PJM Western Hub to Jersey Central Power & Light and PJM Western Hub to Public Service Electric & Gas. Figures 10 and 11 show the volume of FTRs traded in the PJM auctions and the $/MWh clearing prices. Clearly, the volatility of the prices increased substantially in 2004-2005, and in the case of JCPL, the volume of trades did as well.

Figure 10

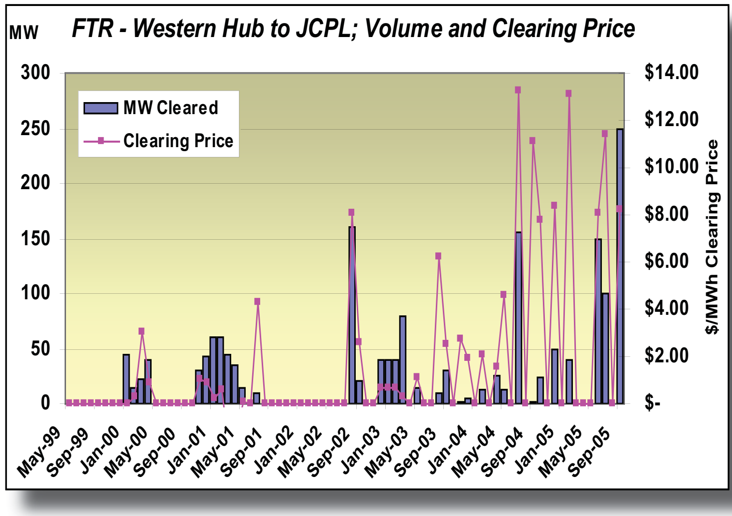
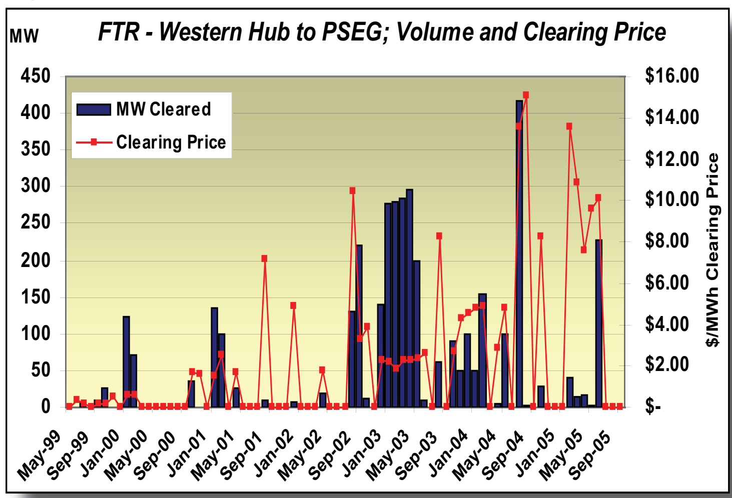


Figure 11



We will review changes in PJM zonal energy prices later in this report. At this point, our interest is in measuring the relationship between the prices paid in the FTR auctions and the ultimate actual energy price difference between each of the two New Jersey zones and the PJM Western Hub in the monthly auctions for on-peak contracts.

As was the case with the energy price itself, we should not expect the FTR auctions to "predict" the correct zonal pricing difference. For the FTR market to be an effective hedging arena, however, we should expect to see only a small or no bias – on average – in the FTR auction price in relation to the actual price differences in the day-ahead markets.

Figures 12 and 13 show the now-familiar pattern of a forward market – the one-month ahead FTR auction – that "always gets the spot price wrong" but nevertheless constitutes an effective hedging arena because its results are not biased. The average "error" of the Western Hub – PSEG market is $-0.34/MWh, and of the Western Hub – JCPL market is $-0.36/MWh.

Figure 12

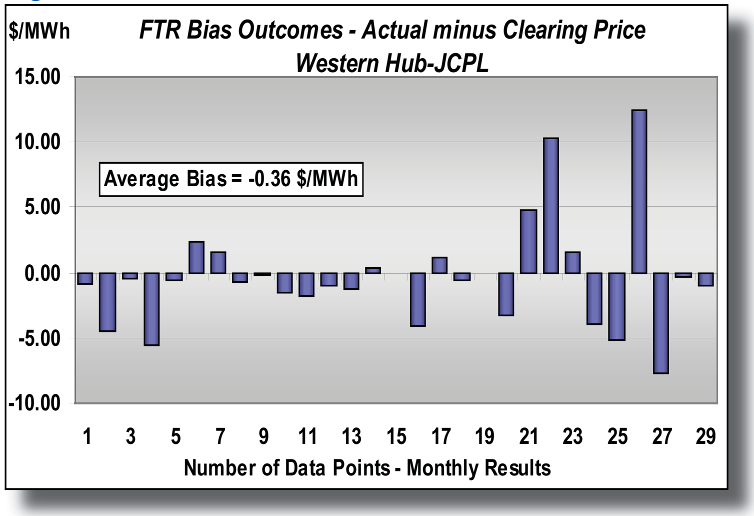
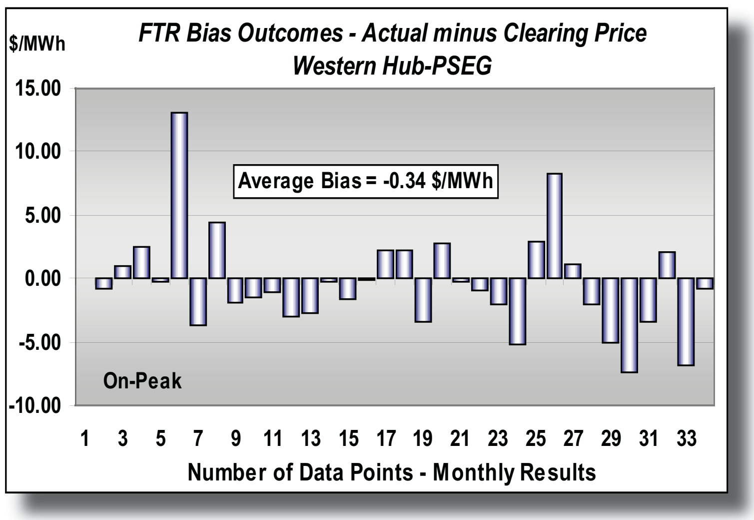


Figure 13



The Critical Importance of Unbiased PJM Forward Markets

On the basis of our analysis of the PJM forward markets, we conclude that PJM is a market in which short-term risks can be effectively hedged. There continues to be a need for additional progress in the depth and liquidity of longer-dated contracts, especially for the regional indexes. However, given the confidence that we believe market participants have in the PJM platform, we believe that these liquidity improvements will continue.

Why are these indications of unbiased forward markets important?

In traditional market areas, one entity – the utility—essentially constructs the forward curve and in that curve are embedded its assumptions about the future, including judgments about the future price of input fuels, judgments about technology, and judgments about environmental preferences and impacts.

In a competitive market area, many entities – consumers, utilities, producers, and speculators – by their trading in spot and a variety of future contracts, develop a forward curve in which are embedded a wide variety of participants' views on the future of fuels, technology and environmental constraints. Each of these participants' views is influenced – to a greater or lesser degree – by what Coase called the competitive struggle that is a "stimulus to improvements of all kinds."

One cannot rule out that a particular utility might be able to make these judgments better than the array of participants in a market. After all, in the investment arena some money managers do appear to excel, year after year. But in spite of the existence of a few stellar performers, most investors still prefer to entrust their savings to a number of managers (in the form of investments in different companies, mutual funds, and savings vehicles).

As PJM's forward markets provide an increasingly unbiased series of forward markets, they offer market participants an escape from a particular manager's view of the future. In this respect, across PJM's newly expanded market area, consumers' reliance on PJM's forward markets will turn out to be costly only if the utility which formerly constructed their forward market was particularly and peculiarly prescient.

PJM, in short, offers an array of forward markets in which consumers' dependence on electricity can be hedged – risk-managed, if you will -- on an ongoing basis by a wide variety of market participants.

This argument is not new. It is a variant of the most conservative approach to investment – the reliance on a portfolio (in this case, a variety of contract periods and market counter parties). This argument can be extended to PJM even further, as we do below.

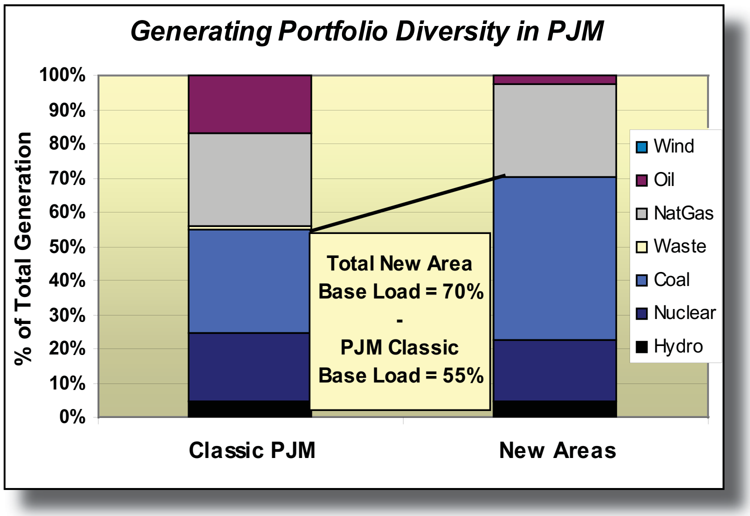
Markowitz's Revenge: The Benefits of Generation Portfolio Diversity

PJM's expansion into parts of Virginia, West Virginia, Kentucky, Ohio, Indiana, and Illinois consolidates the diversity of its generation portfolio, and provides consumers in each area – old and new – with the benefits of that portfolio diversity.

In the last five years, the value of that portfolio diversification has been established more clearly than ever before because of the extremely rapid increase in the price of natural gas. As mentioned elsewhere in this report, over the past ten years, the attractive features of combined cycle natural gas generating systems led to an enormous increase in the reliance on natural gas to generate electricity. In the U.S. power market, California now powers 60 percent of its generating capacity with natural gas, Entergy 68 percent, New England 47 percent, and New York 38 percent.

Prior to the integration of the areas south and west, PJM (including Allegheny) already had a much more diverse portfolio than these other markets, as shown in the chart below. The new PJM areas (Dominion, AEP, DPL, etc) also had maintained similarly diverse portfolios. Thus, the integration of the new market areas into PJM consolidated the traditional diversity of PJM's generation portfolio.

Figure 14



In the U.S. power markets most dependent on gas-fired generating resources, the impact of runaway gas prices on power prices has naturally been stronger than it has been in either PJM classic or the expanded PJM. This is the consequence of decisions made years ago in those markets that sought to reduce the role of oil and coal in the portfolio of electricity generating assets. The reasons for this decision are clear enough – natural gas was everyone's favorite fossil fuel. In combined cycle generators, it is an extremely efficient and clean way to generate electricity.

The preference for gas was present not just in political jurisdictions. There were power companies who specialized in building and running gas-fired facilities. Their portfolio of assets had little if any diversity. Wall Street, by and large, did not penalize these companies for their lack of diversity until comparatively recently. To the contrary, many Wall Street analysts reckoned that having lots of gas-fired plants in a portfolio was better than having an assortment of technologies in the portfolio. So, some companies in America and Europe virtually gave away their old nuclear, coal, and oil plants to raise money to build new gas plants.

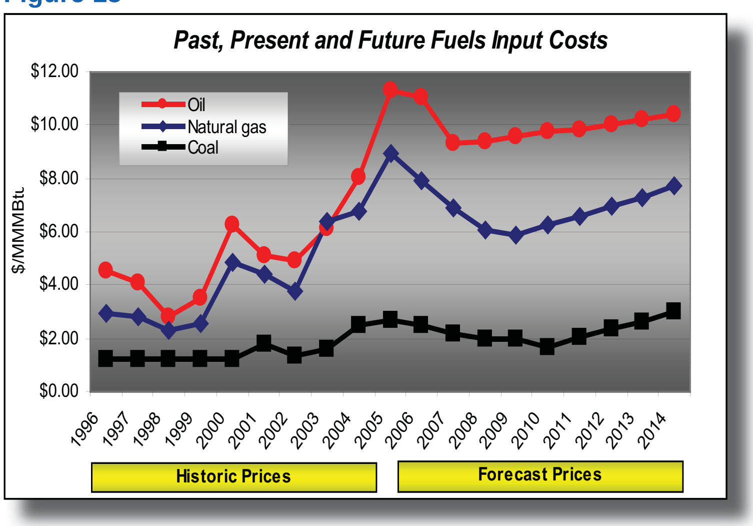
There was a tremendous risk in this gas obsession. It is surprising that this risk was allowed to exist because most of the same people who took this risk in the power portfolios would have recoiled from embracing such a risk in their retirement accounts. The risk: that the absence of diversity increased the exposure of the gas-oriented states and companies to the vicissitudes of the natural gas market, which already was one of the world's most volatile markets in 1998, and became ever more volatile in subsequent years.

The Costs of an Absence of Diversity in a Generation Portfolio

The costs of having more or less diversity in any portfolio can be readily calculated with the instruments of modern finance. Modern portfolio theory stems from Harry Markowitz's *Portfolio Selection – Efficient Diversification of Investments* (New Haven: Yale University Press, 1959). Markowitz developed a model of efficient portfolios as those lying on the "efficient frontier," where "yield can no longer be increased without increasing the risk, and risk cannot be lowered without lowering the yield."[5] In this formulation, risk can be defined and quantified as the variation in a portfolio's return. In the case of a state's (or a power producer's) generation portfolio, risk can be quantified as the variation in the average energy input price as a result of moving from one portfolio to another.

The issue, then, is for a state government, or a power generating company, to assess the risk of moving from one portfolio of generating assets to another. Assume the following scenario. A power generating company has four types of units in its portfolio: oil, gas, coal, (all of which have commoditized input fuels costs) and nuclear-hydro-wind (which do not have commoditized input fuels costs).

Figure 15



The input fuels costs of natural gas and oil units have been extremely volatile over the last ten years (as shown in the chart above). The price increases of natural gas have been, by far, the most consequential for the power sector because gas became, in many areas, the fuel of choice in the 1990s. As a result, the price of electricity in those areas became more and more dependent on the price of natural gas.

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[5] Ralph Vince citing Markowitz in *Portfolio Management Formulas, Mathematical Trading Methods for the Futures, Options, and Stock Markets* (New York, John Wiley and Sons, 1990), p. 152.

Looking ahead, most energy forecasters believe the price of natural gas will remain in the $6-$8/MMBTU level, distillate fuel oil prices above $10/MMBTU, and coal in the $2-$2.50/MMBTU range (excluding the cost of emissions compliance). For coal, emissions costs for some plants may be met by including them in the rate base. If so, electric energy prices from these coal facilities are likely to continue to reflect input fuels costs in the $2 - $2.50/MMBTU range, exclusive of emissions costs.

We can evaluate the effects of increasing dependence on a single fuel -- natural gas -- using standard measurement techniques. Assume two different generation portfolios.

- ✓ In the first portfolio, natural gas comprises 75 percent of generation capacity, coal comprises 10 percent, nuclear and wind (fuels with negligible input fuels costs) another 10 percent, and oil 5 percent.

- ✓ In the second portfolio, natural gas comprises 25 percent of generation capacity, coal comprises 35 percent, nuclear and wind (fuels with negligible input fuels costs) another 35 percent, and oil 5 percent.

The table to the right shows the assumed level of future input fuel prices. Different price forecasts would naturally produce different portfolio results but the prices presented here are representative of forward market and expert opinion as of the end of 2004. Therefore, they are likely to be the basis of planning in electric areas and of investments in the generation sector.

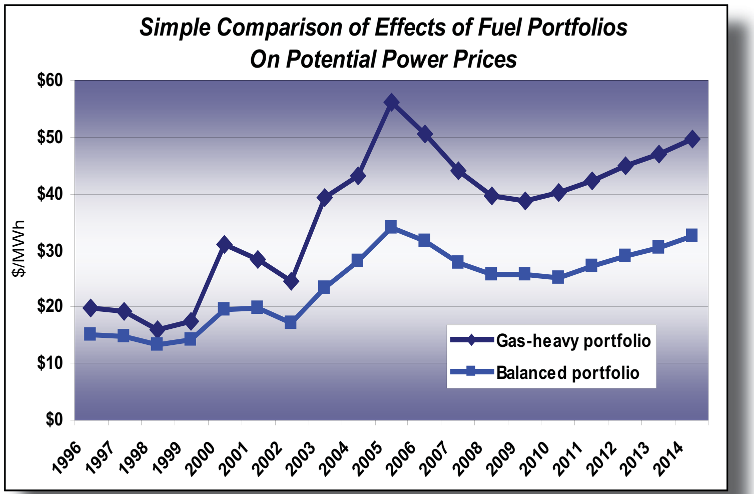
Assumed Fuels Input Prices for Portfolio Analysis ($/MMBtu)

	Tetco M3	Coal PJM	#2 Oil
1996	$2.92	$1.24	$4.53
1997	$2.83	$1.24	$4.06
1998	$2.32	$1.24	$2.82
1999	$2.55	$1.24	$3.51
2000	$4.87	$1.24	$6.25
2001	$4.42	$1.76	$5.11
2002	$3.74	$1.35	$4.89
2003	$6.41	$1.61	$6.11
2004	$6.77	$2.49	$8.05
2005	$8.91	$2.65	$11.31
2006	$7.89	$2.49	$11.04
2007	$6.87	$2.19	$9.30
2008	$6.08	$2.01	$9.38
2009	$5.90	$2.01	$9.55
2010	$6.23	$1.68	$9.77
2011	$6.56	$2.05	$9.85
2012	$6.95	$2.34	$10.03
2013	$7.27	$2.64	$10.21
2014	$7.71	$2.98	$10.40

Figure 16 presents the consequences of the concentrated dependence on natural gas in the first portfolio. It presents an estimate of the weighted average cost of electric energy on each market on the basis of simplified efficiency assumptions (the gas power plants manufacture electricity at a 7 MMBTU/MWh heat rate, and the oil and coal plants at 10MMBTU/MWh; and nuclear and wind facilities bid into the markets at $10/MWh; and there are no other generating costs).

In the 1996-2005 period, the weighted average price of electric energy in the market with 75 percent dependence on natural gas was on average $8/MWh higher than it would have been in the market with the more diversified generation portfolio.

Figure 16



As the demand for natural gas increased during this period, the price in relation to other input fuels also increased. Even with an expected increase in natural gas imports (mostly via liquefied natural gas), most forecasters still expect natural gas prices to remain in the $6 to $8/MMBTU range. Thus the markets with the heaviest dependence on natural gas for generating electricity will continue to see relatively higher electric energy prices than the more diversified markets.

The schedule of inputs fuels prices shown in the table above would lead to a difference of $15/WMh in the calculated energy prices of the same two portfolios. For the 2006-2015 period, the balanced portfolio would see an electric energy price averaging $28/MWh, the gas-heavy portfolio a price averaging $44/MWh.

Application to PJM

The risk-management advantages inherent in a diversified portfolio accrue to both sides of PJM, but in different manifestations. In PJM East, there is a propensity to construct mostly natural gas plants. In PJM West, there is a propensity to construct coal plants. On the basis of the portfolio argument made above, PJM East benefits from its membership in PJM to the extent that the rest of PJM is able to maintain a substantial amount of coal in its portfolio.

At the same time, however, it will be in the interest of PJM West to obtain portfolio diversity from PJM East. There is no guarantee that the large price difference between natural gas and coal shown in the charts above will be sustained over the next decade. Indeed, those who believe in the strength of market forces may well believe that with investments in natural gas infrastructure (especially LNG) *and* with increasingly stringent requirements on coal emissions (sulfur dioxide, nitrogen oxide, mercury and carbon), we may well see substantial increases in the overall cost of burning coal, and we may well see those increases reflected in electric energy prices (rather than only in the capacity markets).

In that case, a scenario in which natural gas prices fall back to the $3 - $4 range and the "all-in" cost of coal rises above those levels cannot be discounted. Our analysis of the higher costs of energy in the highly gas-dependent market will then be stood on its head, with the coal-fired regions suffering from the higher energy prices.

This portfolio analysis can be done at a much more refined and sophisticated level. But what we have done here suffices to make the primary point, which is that predictions about the generation technologies of choice in the future are as difficult to make as predictions about the stock market. PJM provides a framework for all of its regions to continue to obtain and maintain a diversified portfolio of generation assets, which will in the long run provide a most effective form of risk management for all of its customers.

Finally, and to summarize, the reduction in "single-agent" risk, the reduction in the bid-ask spread, and the lack of bias in forward markets in the PJM package have tremendous value for market participants. If, over the course of the decades in which these efficiencies must be measured, the price of electric energy turns out to be only $2/MWh less than in a world of monopoly agents, the economic benefits of the spread of PJM's platform would be measured at $1.4 billion per year (given PJM-wide load of 678 terawatt hours per year), or $15.7 billion over a twenty year planning period (and a six percent discount rate).

IV. The Development of PJM Capacity Markets

Electricity is a necessity. As a result, reliability of electric supply is so important that its assurance continues to be subject to regulation, even though the overall intention of policy-makers has been to subject electricity market participants in the wholesale sector to the "competitive struggle."

Historically, regulators typically ensured reliability by imposing reserve generation capacity requirements on utilities. The utility was required to forecast its peak load, and to build or contract for capacity at some designated percent (for example, 15 percent) above that peak load.

This arrangement often failed to motivate the utility to develop alternatives to generation – like demand restraint programs or alternative types of transmission – that might also contribute to reliability. For example, a program that would predictably but temporarily reduce electricity demand could add as much to overall reliability as a "peaker" generator plant (i.e., one built just to run a few hours or days a year), but did not get implemented because the emphasis of the regulations was on generation.

The traditional reliability programs had another disadvantage. Experience has shown that reliability is more expensive to maintain in some areas than in others. For example, it is likely to cost more to maintain a certain level of reliability in an extremely remote rural area or in a densely populated city than in other areas. Imposing a system-wide reserve margin of 15 percent may do little to ensure reliability in these locations.

Reliability planners have responded to these challenges in a variety of ways. In New York, reliability rules require that load-serving entities in New York City not only participate in the state-wide program to maintain a reserve margin, but also require 80 percent of the peak load in the City to be capable of being met by resources located within the city (the so-called locational capacity requirement). It costs substantially more to build electric facilities in New York City than in upstate New York, thus reliability is a correspondingly more expensive service to provide in the City.

After a decade of experience with restructured markets, it is now clear that the design of a competitive wholesale power market should take account of these two central challenges to maintaining reliability – encouraging a variety of responses to maintaining reserve margins and accounting for different locational costs. In PJM, the initial design of the "capacity market" did not do so: instead, it provided for reliability payments only to generators and for the same payment regardless of the location of the generators. These characteristics of PJM's capacity market design were reflected in the "standard market design" promoted in 2003 by the Federal Energy Regulatory Commission.[1]

[1]Federal Energy Regulatory Commission, *Wholesale Market Platform*, (White Paper), April 23, 2003

The implementation of this initial design coincided with a period – as discussed later in this section – of "irrational exuberance" in generation development, although there was little market-based investment in demand restraint or transmission alternatives to generation. The economic consequences of the initial market design were not transparent while generation investment boomed from 1996 to 2003. By 2004, however, those consequences were becoming transparent. Payments to generators for their reliability services collapsed. With that collapse, merchant investment in new generation came to a virtual standstill, and even investment in maintaining the existing stock of generators came under severe pressure. The first of several waves of retirements of generators was announced. Not surprisingly, the bulk of the retirements occurred in those areas of the market where generation was most expensive to maintain.

Thus, by 2004, it was clear that the initial design of the markets that promote payments for reliability needed to be improved. The challenge was to find a program that would structure payments that better reflected the underlying value of the services, and that better reflected regional differences in the cost of maintaining reliability.

PJM's response to this need is the Reliability Pricing Model. It came after several other areas – most prominently New York and New England – had developed their own alternatives to the initial market design.

PJM's Generation Capacity and Reliability Policy

There have been ongoing discussions in all organized power markets on how to deal with the capacity and reliability issue. Approaches vary. PJM maintained its current approach until it decided on an alternative in early 2005 (see the discussion of its Reliability Pricing Model below). New York developed a "capacity demand curve" and locational capacity requirements that amount to a retreat from the original standard market design model. New England has developed its own version of New York's model. California has finally enacted a reserve requirement, but has not yet defined an ISO-directed capacity market.

These ISO/RTO capacity market designs are critical. If they don't work, given investor wariness of electricity assets, the only alternative way to finance a new power plant or transmission line or demand restraint program is the old-fashioned way: a long term contract with a credit-worthy entity.

Why Do We Need A Capacity Market Policy Anyway?

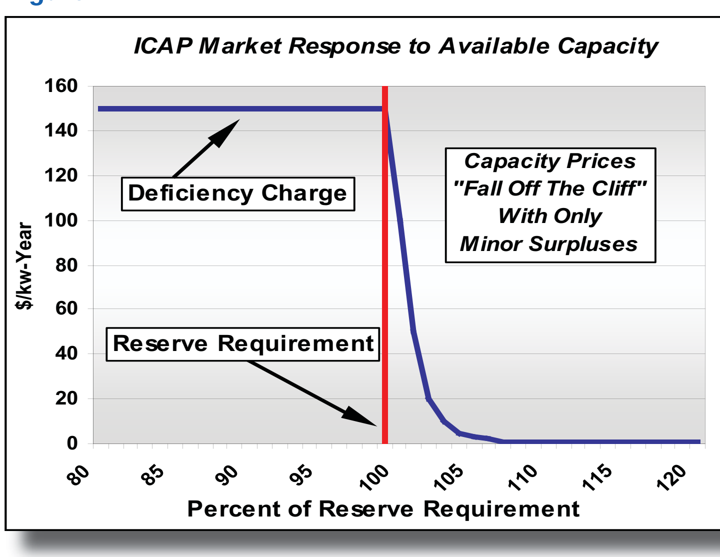
To outsiders, it seems at first odd that the federal or state governments have to deal with whether or not there is enough electricity generation capacity. After all, there is no particular requirement for capacity in petroleum refining. Deregulation in the oil industry was based on the premise that market forces would sort out the amount of capacity that would be required. When refining capacity has been inadequate, business has found ways either to expand capacity in the market area or bring in supplies from more distant areas.

As those in the power business know, however, two factors mitigate against such a *laissez-faire* approach in electricity. First, modern society relies on electricity for provision of basic services that cannot be replaced by other services, at least in the short run. A disruption in electricity services, therefore, has consequences far beyond the loss of revenues to the immediate power buyer and seller. Second, all electric assets in the three primary U.S. electric interties are essentially parts of three enormous machines.[2] The integrity and reliability of these machines cannot be put into jeopardy. These machines require a reserve margin to ensure that periodic failures of its component parts (generators, groups of generators, and transmission facilities) do not bring the entire machine to a halt.

While the reasons for requiring reserve margins are obvious, how best to ensure that these margins are maintained is not. Early in the deregulation process, the notion that one could employ the market for this particular requirement was widely held. New England, PJM, and New York ISOs all experimented with capacity markets, each of which exhibited several curious characteristics. First, the capacity market experiments occurred in the midst of an enormous boom in generation construction. This period of irrational exuberance created an enormous glut of capacity in areas where it was easy to build (permits were easy to get, gas pipelines were nearby, and eager investors and bankers could always be found). Under these circumstances, in most areas, the supply of capacity was so far greater than the demand that the capacity market sent the right signal – *on the margin, capacity was worth nothing*.

Second, the capacity market experiments showed that, once the demand for generation capacity was met by the amount defined by the required reserve margin, demand collapsed to zero (see Figure 1). Unlike most other goods (computers, automobiles) whose marginal utility to the buyer declines incre-

Figure 1



[2] The Eastern, Western and "ERCOT" (most of Texas) interties.

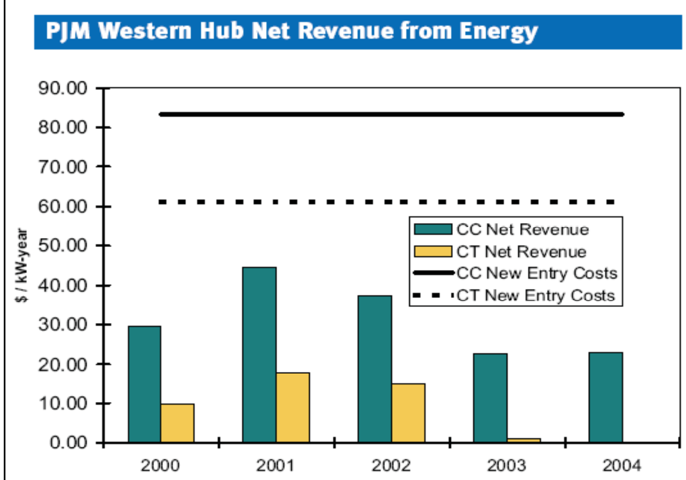
mentally, the value of surplus capacity to a load-serving entity (whose revenues are regulated according to the costs it incurs) is zero. So where capacity additions exceeded the requirement, load serving entities were in the advantageous position of offering its marginal value - near zero - to all suppliers.

Thus, capacity values — as determined by capacity markets in PJM, New England, and other areas with surplus generation — have been negligible. Power plants built on the assumption that their owners could command capacity fees of $30 to $100 per kilowatt per year (depending on the cost of construction), found they were getting next to nothing from capacity payments, and as a result, many of the owners of those plants slid into bankruptcy. Banks now own some 70,000 MW of distressed power plants, largely for this reason.

The Outlook for Resource Adequacy in PJM

With the collapse of capacity payments and the dramatic reduction in proposed generation projects, PJM's reserve margins are now expected to drop from 25 percent in 2005 to only 18 percent in 2010 (the required reserve margin is 15 percent).[3] The PJM reserve margins may decline even more quickly. The Federal Energy Regulatory Commission, concerned about the decline in investment in new generation in all U.S. power markets, reviewed the adequacy of energy and capacity revenues during the 2000 to 2004 period to meet the cash requirements of those who have invested in generation in both traditional and RTO/ISO market areas, including PJM.

Figure 2



Source: Derived from Platts and EIA data. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details. See also source note 10.

FERC 2004 State of the Markets Report, p111.

[3]Energy Security Analysis has conducted its own assessment, which came to a similar conclusion (for ESAI's assessment, see www.ESAI.com/PJMCapacityReport.htm)

The bottom line of the report is that "market fundamentals in 2004 did not generally signal a need for new construction of generation, particularly of gas-fired capacity."[4] Figure 2 presents FERC's assessment of the adequacy of PJM's energy revenues to provide a reasonable rate of return to a combined cycle or combustion turbine in the PJM market. Revenues from PJM's capacity auction added only a few dollars per kw-year to the energy revenues. The FERC report's conclusion: "*Without significant net revenue from energy, capacity, and ancillary services, market-based investment was not signaled.*" (page 111).

In PJM, as elsewhere, the only generation capacity that is expected to join the grid in the next several years is in the form of:

1) Wind units - (there are now 74 proposed wind interconnections in PJM totaling 1,300MW) and other small-scale renewable units,

2) Coal units - that will be built largely in the western part of PJM, most of them with some utility support, and,

3) Gas units - that were initiated in the good old days of the merchant generation boom, and whose completion has been slowed to a crawl while the developers wait for more favorable market circumstances.

In some areas of PJM, generation investment needs to resume right away. But there is no investment because of the mismatch between the short-term signals from the capacity markets and investment requirements (which are long-term in this capital-intensive sector of the business). Merchant investors – responsible for the bulk of the 1998–2003 boom in generation capacity – have lost their shirts and their confidence, while utilities are reluctant to - and often prohibited from - issuing long-term contracts to mitigate the merchants' risk.

That mismatch is at the center of the discussion on where the PJM and other restructured markets go from here. PJM's proposed Reliability Pricing Model (RPM) has among its objectives to address the mismatch between short-term capacity market price signals and long-term investment requirements by reducing the volatility of capacity revenues that today's developers in generation, demand management, and transmission projects face.

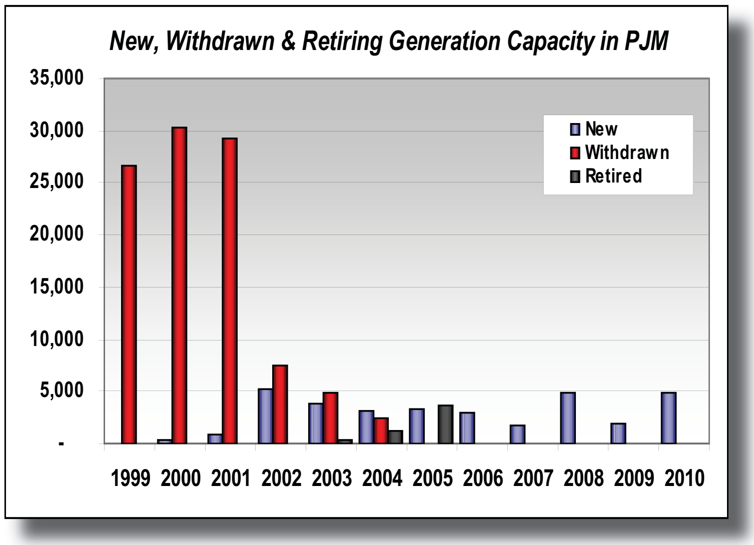
The PJM Queues

Figure 2 reviews the activity in PJM's *generation* queues (there is a separate series of queues for independent transmission projects). In the early years of the process, annual average *proposed* generation additions amounted to more than 25,000 MW per year. Clearly, this signaled intense competition among generators for the most favorable interconnection locations. Over the

[4]Federal Energy Regulatory Commission, *2004 State of the Markets Report*, Washington D.C., 2005, p. 26.

course of 1999 to 2005, more than 130,000 MW of generation interconnections were proposed, while 16,000 MW was constructed (with almost 13,000 MW still in various stages of active development). Thus, 100 thousand MW of new generation proposals have been withdrawn from the PJM development process. This is to be expected in a market environment. To the extent these withdrawals occurred because the interconnection costs were too high, or some other part of the development process went awry, the only losers were developers.

Figure 3



Projecting this harsh project-weaning process to the future, PJM expects only about 4,200 MW of the 13,000 MW still in the development queues to be completed by 2010. The total new capacity that will be added to PJM in the decade from 2000 to 2010, therefore, will be approximately 20,000 MW.

This is a substantial addition, to be sure. Beginning in 2003, however, the crushing impact of the collapse in capacity market values began to take its toll: more than 300 MW were retired in 2003, 1100 MW in 2004, and almost 3,600 MW in 2005, for a total retirement of more than 5,000 MW. Given these retirements (and ignoring others which are sure yet to be announced), the net increase in PJM's capacity in the 2000 – 2010 decade will be reduced from 20,000 MW to 15,000 MW.

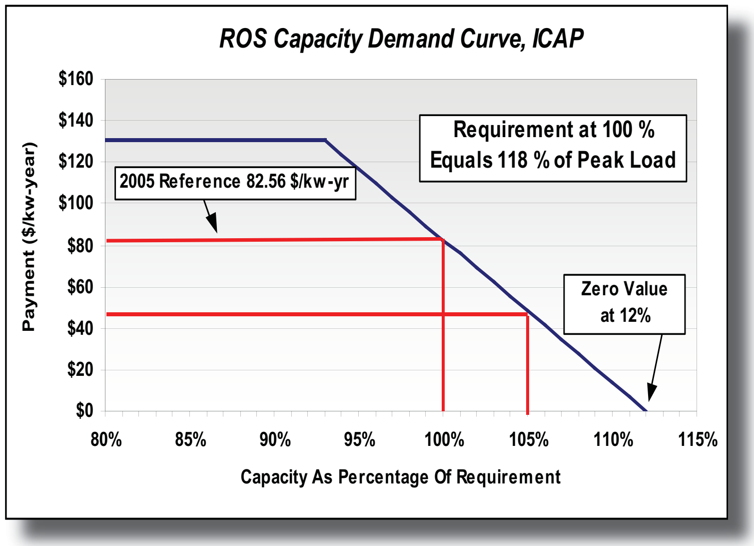
Given the PJM RTO's load growth of 2 percent or 2700 MW per year, this 15,000 MW increase in capacity gets used up quite quickly, hence the projection from PJM that its reserve surplus is essentially depleted by 2010.

To make matters even more interesting, much of the new capacity that remains in the queues is in the form of wind. How much of the 1,300 MW of wind capacity developed will actually count towards meeting PJM's reliability requirement remains to be seen.

The Development of the Reliability Pricing Model

In recognition of the need to improve the payment scheme of the original reliability/capacity market design, regulators in the New York Public Service Commission first developed an approach – the capacity demand curve – that plots available supply against a pre-determined curve to develop a clearing price for the month[5]. Figure 4 illustrates the demand curve construct for New York's "Rest of State" (i.e., the market area excluding New York City and Long Island).

Figure 4



The key components of the demand curve are the reference point and the zero value point. The reference point represents the pre-determined value of the market when the reserve requirement is exactly met. In the case of New York State, this 100 percent of the reserve requirement is met when available capacity exactly meets 118 percent of peak load. The value of capacity services at this reference point is set at a level representing the fixed costs associated with installing and operating a new peaking combustion turbine. As noted on the chart nearby, this cost is calculated at $82.56/kw-year for the New York ROS (Rest of State) market, 2005 basis.

The second reference point represents the point on the supply axis where the capacity value is zero. In the New York ROS market, the capacity value drops to zero when reserve margins are 112 percent of requirements. (For New

[5]Mark A. Reeder and Thomas S Paynter pioneered much of the thinking behind the capacity demand curve. See Market A. Reeder, "Government Intervention into Wholesale Electric Markets to Assure Generation Adequacy", (Nov 6, 2002), mimeo, New York State Department of Public Service, and Thomas S. Paynter, Affidavit of Dr. Thomas A. Paynter, FERC Filing of the NY State Public Service Commission, Attachment I, Docket No. ER03 - 647 - 000, (April 11, 2003), available at www.dps.state.ny.us/EnergyCompetition.html.

York, this means that the total capacity would be 112% in excess of the 118% requirement). If the available supply is 105 percent of requirements, then this point on the curve is used to determine the clearing price. On the chart above, this clearing price is shown as near $45/kw-year.

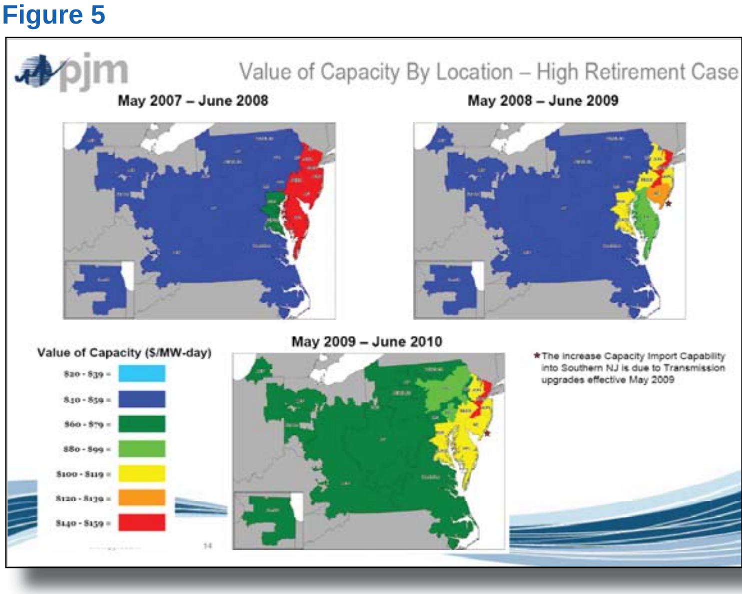
Load serving entities are allocated the full cost of capacity services that clears in the auction even though the supply of these services may be in excess of requirements. All available services that clear will receive a capacity payment. LSEs receive a lower price when supply is in excess of requirements, but they will be required to foot the bill for more supply than they need through the allocation process in place at the ISO.

The demand curve provides a more stable stream of revenues for those who provide reliability services when the market is in excess of reserve requirements. It also provides a mechanism for forecasting capacity values in the future, as new projects and retirements can be added to predict future available supplies against anticipated load growth. This allows developers to project more reasonably what can be expected from the capacity markets with any given investment scenario.

RPM

In the wake of New York (and later New England's) development of new capacity market constructs, PJM developed a detailed, new market construct called the Reliability Pricing Model (RPM). It is based on the need to acknowledge, "that if generation capacity in a particular location is critical to reliability, it should be valued accordingly. With the appropriate locational valuation of generating capacity and a longer-term resource commitment, owners of existing resources will have the appropriate incentive to make the investments needed for their units to stay in the market, and project developers will have the appropriate incentive to locate new resources where they are most

Figure 5



needed."[6] In this respect, the RPM is similar to the locational capacity requirements pioneered by the New York ISO.

The pattern of capacity values across PJM has not yet been definitively established. Early PJM presentations (see Figure 5) indicate that values increase from West to East. Values in the eastern zones will be higher due to the added reliability of locating generation in constrained load pockets.

The RPM expands on the other concepts by allowing independent, economic transmission projects (projects not financed by the RTO to meet reliability requirements) and demand management programs to compete with generation to meet locational capacity requirements. When such a non-generation solution relieves a load pocket, it will be paid for the capacity consequences, and not just the energy consequences, of that relief.[7] This is a significant innovation in competitive market design.

The next significant feature of the RPM proposal is PJM's version of how the payment for reliability/capacity services will be determined. Instead of a single ICAP market and single clearing price, PJM, like New York, will institute a "capacity demand curve" (that is, a schedule of payments arrayed along a series of capacity surplus and deficit measures). The greater the deficit in this construct, the higher the payment. In PJM's terminology, "Under RPM, there will be separate variable resource requirement ('VRR') curves … determined for each LDA [Locational Deliverability Area], reflecting differences in the cost of new entry for those LDAs…"[8]

Each PJM area's VRR curve will resemble the example shown in Figure 6, with a capacity price in dollars per MW-day established for a given reserve margin. If generator investors are too exuberant and develop capacity in excess of 20 percent above the reserve margin, the capacity payment will fall to zero. If there is sparse investment and the capacity surplus falls to zero, the payment would be $350 per MW per day.[9] Behind these figures is an array of evaluations of the cost of building specific types of marginal units in the different market areas.

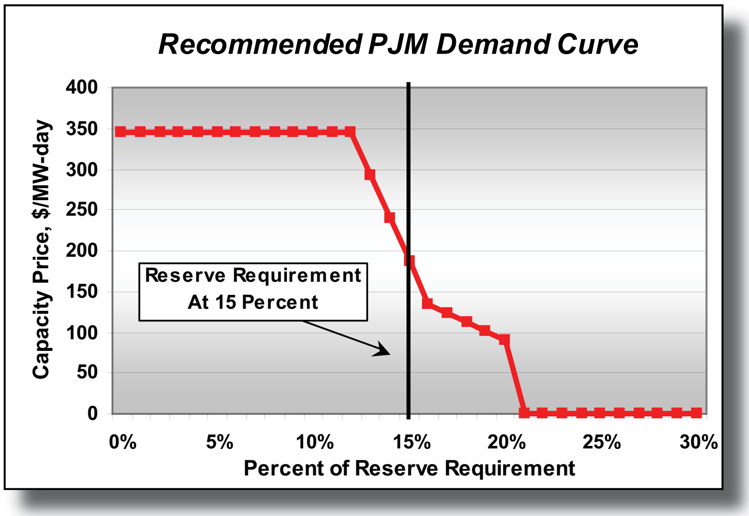
[6] "Affidavit of Steven L. Herling On Behalf Of PJM Interconnection, L.L.C. Before the Federal Energy Regulatory Commission", August 30, 2005, page 10.

[7] In the language of the draft RPM Business Rule 89: "The offer price of a Participant-Funded Transmission Upgrade offer shall be considered as a capacity price differential between the source LDA [a.k.a. Locational Deliverability Area] and sink LDA in the Base Residual Auction clearing process."

[8] Herling Affadavit, p. 12.

[9] "Affidavit of Andrew L. Ott On Behalf Of PJM Interconnection, L.L.C. Before the Federal Energy Regulatory Commission", August 30, 2005, page 4.

Figure 6

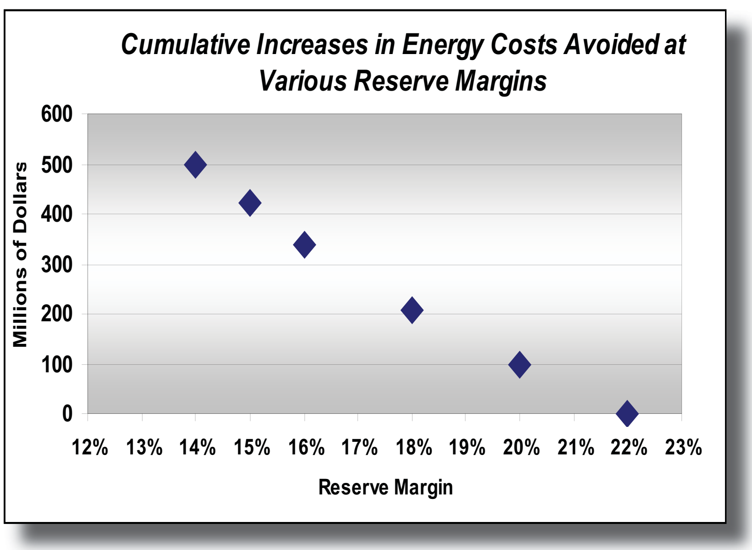


Effects on Energy Prices

The net cost of any capacity policy cannot be understood in isolation from its spillover effects on the energy market. It stands to reason that the more any market can attract a diverse portfolio of efficient generating plants, the lower the energy price will be. There have been a number of studies from PJM and others with calculations that show – under specified assumptions – how energy prices rise as the PJM reserve margin falls, and vice versa.

Figure 7 is based on PJM's analysis, and shows the cumulative effects of increases in energy prices as the reserve levels fall from 22 percent to 14 percent.[10] The impact is quite substantial, amounting to $500 million per year should reserve levels fall from 22 percent to 14 percent.

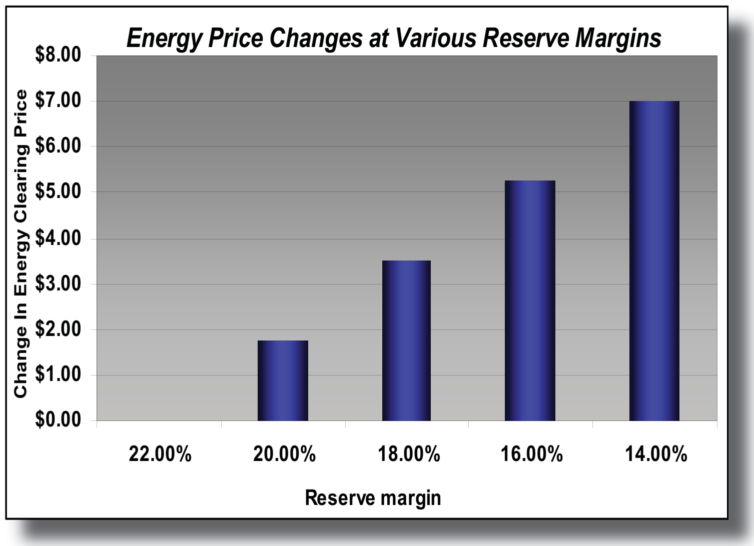
Figure 7



[10] Based on figures provided in Ott Affadavit, p. 24.

Figure 8, based on a conservative, production-cost based PJM analysis, shows energy prices going up by $7/MWh as reserves fall from current levels of 22 percent to 14 percent which could occur as early as 2011 (keeping fuel prices constant for comparability). This is based on a calculated 7x24 market heat rate of 6,100 Btu/kw in 2005 and 7,100 Btu/kw in 2011. This 1,000 Btu/kw swing in heat rate at a $7.00 gas price would result in a $7.00/MWh increase in 7x24 prices. At a demand rate of 700 TWh per year, this represents a $4-5 billion per year swing in energy costs by 2011. As the reserve levels are reduced, the energy cost will increase, because the least efficient generation units will be setting the price more often. [11]

Figure 8



Netting Out

Finally, to ensure that the capacity payment is not excessive, PJM has added a netting provision to the RPM:

> "If a new unit is to recover all of its costs from the PJM markets in equilibrium, the unit needs to recover from the capacity market only those costs not recovered in the other PJM markets. A competitive offer price in the RPM market for a new CT for its first year of operation equals the total annual fixed costs of the CT, less expected net revenues from all other sources. This is the incremental cost of new capacity. Accordingly, the Cost of New Entry (CONE) value … must be reduced by an amount equal to the revenue a new CT can expect

[11] See also "Affidavit of Benjamin Hobbs on behalf of PJM Interconnection, LLC Before the Federal Energy Regulatory Commission", August 5, 2005 for a more extensive analysis of potential outcomes.

> to receive from the PJM energy and ancillary services markets, less the variable expenses incurred to obtain those revenues ('revenue offset')."[12]

The intent of netting out estimated energy and ancillary service revenues is to ensure that the RPM is an efficient floor on generator earnings. Hence the emphasis on the costs of the marginal unit in PJM markets "in equilibrium." Because these revenues cannot be accurately forecast, PJM has decided to use the average revenues from the past six years as its benchmark:

> "PJM will determine the energy market portion of the revenue offset as the annual average of the revenues that would have been received by the 'Reference Resource' in the preceding six years based on '(1) the heat rate, variable cost, and other characteristics of the Reference Resource; and (2) the actual fuel prices and Locational Marginal Prices experienced in the PJM Region during such six-year period.' Under this approach, the revenue offset is equal to the net revenues calculated based on how a unit with the characteristics of the CT for which the CONE is calculated would have operated under actual PJM prices."

Effect of RPM

As this review indicates, there is growing consensus in the analytical and the regulatory communities that something like the RPM is needed to supplement energy revenues, in an environment in which investors expect energy revenues to be capped at precisely those times when they might increase by enough to cover capacity costs. The RPM is a pragmatic approach to providing a floor on earnings that should be sufficient to motivate the next round of investments in generation capacity and its transmission and demand management substitutes.

The PJM generation queues show that there is investor interest in areas where energy revenues are augmented by other sources. There are, as shown earlier, 1,300 MW of wind projects in the PJM queues, all developing in response to federal and state incentives to renewable energy sources. There are also multiple DC transmission projects in the PJM queues, developing in response to New York-based long-term contract opportunities. Even though these development projects are responding to incentives and/or contract opportunities, they are still exposed to substantial development and market risk, and therefore indicate that – given a supplement to energy market earnings – there is keen investor interest in investing in PJM.

Finally, discussions about electricity market restructuring often reveal fundamental differences in belief about how markets are *supposed* to work. At one

[12] "Affidavit of Joseph P. Bowring On Behalf Of PJM Interconnection, L.L.C. Before the Federal Energy Regulatory Commission", August 30, 2005, page 3. Mr. Bowring is PJM's Market Monitor.

end of the opinion spectrum are the proponents of market forces, who argue that the energy price mechanism simply needs to be allowed to work, even if that means the price of energy goes to $10,000 in some hours. It may go to those levels for a lot of hours in some years and very few in others, which is the investor's problem. But as a principle, the price mechanism must be allowed to do its thing, and to throttle it with price caps is to risk getting on the "slippery slope" back to regulation.[13]

At the other end are the opponents of market forces. They base their opposition on the events in California, the behavior of some trading companies, on the view that electricity cannot be commoditized because it is cannot be stored, is a public good, and a natural monopoly, and thus needs to be comprehensively regulated. The "slippery slope" in this world-view is that allowing market forces room to maneuver invites market manipulation and gouging of consumers.

In the middle are the practitioners and investors, forced to be pragmatic by virtue of the fiduciary and financial commitments they have made. For those in the practical middle, "slippery slope" is just a metaphor. In the real world, varying degrees of regulation and market forces routinely coexist, and the process of creating a power market where none existed before is an exercise in pragmatism and incrementalism. In this space, the power market of 2005 continues to evolve with state and federal regulators trying to make each regulatory release better, sometimes succeeding, sometimes not.

In this more pragmatic space, the question is not, "Will prices be regulated?" but "How and when will prices be regulated?" because it is clear that $10,000/MWh prices (or even $1,000), even for an hour, simply exceed what the body politic will bear. In this space, the question is not, "Will organized power markets go away?" because it is clear that PJM, the NYISO, ISO-NE, MISO, SPP, and the CAL-ISO are here to stay. In this pragmatic space, where deals are getting done, the actions of ISOs/RTOs are watched with intense interest, because they are the consequences of pragmatic decisions by pragmatic people whose job is to keep the lights on while trying to incubate some degree of market forces in a long-regulated industry. The pragmatists, in other words, expect both regulations and market forces to continuously adapt to each other, and over time these hybrid sets of regulations and market activities reach what may be called an "Angle of Repose," a condition that may not be optimal from a theoretical or doctrinaire point of view, but which works to bring the force of competition into an area that many deem a natural monopoly.[14]

[13] William Hogan of Harvard University has prepared a description of an "energy only" market which has been filed before the California Public Utility Commission by the California ISO. See "On An 'Energy Only' Electricity Market Design For Resource Adequacy, available at http://www.caiso.com/docs/2005/09/23/20050923134305169.pdf

[14] See Edward N. Krapels, "The Angle of Repose for Electricity Restructuring: The 2003 Energy Act, FERC, and the Outlook for Transmission Investment," *The Electricity Journal*, January/February 2004, Vol. 17/1 pp 16-20.

In the ISO/RTO space, an immensely important practical question has now come to the fore: because regulators will mitigate energy prices, investors in merchant facilities claim they must have some form of reasonable compensation beyond just the energy price if they are to recover their capital cost.

And for that reason we have the movement, begun by New York ISO, joined by ISO-NE, and now endorsed by PJM itself, towards the regime of capacity payments that is more predictable than the volatile capacity markets of the original market design.

As we noted at the beginning of this report, and in each section, the essential question for PJM and its new market areas is whether the market construct will bring the competitive struggle to electricity. In the case of capacity markets, the initial market design certainly brought the struggle. But the experience has revealed that the political economy of electricity will simply not allow energy prices to rise to levels sufficient to pay for capacity/reliability services. As a result, investment in new capacity has disappeared, and there is reason for concern.

The RPM appears to us to be one of those areas where appropriately designed regulation can co-exist with market forces and sustain PJM's ability to be a platform for bringing the competitive struggle to the electricity business.

Looking Ahead: Will Investors Invest If the RPM Is In Place?

This brings us to the critical question: what evidence is there that RPM will cause investors to build the new capacity in the absence of long-term contracts from credit-worthy entities? Critics of RPM argue that all it will do is pay existing generators more to stay in business, and that there is no guarantee that the new program will actually cause new capacity to be built.

This is too binary a representation of investor sentiment. Our experience in working with investors, particularly those who have invested in New York –where the capacity demand curve has been in place for several years – indicates a growing willingness to include capacity payments in *pro formas* of future revenues streams. At the moment, these streams are still subject to some discounts – as investors must account for regulatory risk – but we see the emergence of market confidence in capacity revenues under this new paradigm.

V. Electricity (Energy) Price Effects of Integration

In an efficient energy market, measures of the manufacture of electricity, such as the market heat rate, should shows signs of the competitive struggle. In this section, we review energy prices in the "classic" PJM and in its new markets to determine whether it meets that test, and we review technical analysis of the savings from the expansion of the PJM market on the overall market price.

Initial Generation Resource Endowment in PJM and in the New PJM Market Areas

Any measure of efficiency between markets must contend with the fact that markets are endowed with different generation resources, and that each resource has its own distinctive characteristics, especially in the capital cost of construction, and in the cost of input fuels. To cite the most extreme example, a wind turbine has a relatively high capital cost (between $1000 and $1300 per kilowatt), while a combined cycle natural gas plant has a lower capital cost ($500 to $700 per kw). But a wind turbine's fuel is "free" while a gas turbine's fuel is famously expensive (with natural gas prices exceeding $12/million BTU in 2005).

The overall cost of electric energy is mostly determined by the capital cost of the plant and the cost of the input fuel. Putting the two together, once the capital has been invested, a wind turbine can bid its energy into PJM's competitive market at a price close to zero, while a gas-fired generator must always bid a price of energy that pays for its input fuel.

Thus, the following comparison (notional, for illustration purposes only) illustrates how – from an integrated capital recovery and operating cost perspective -- a wind turbine and a gas plant can offer power into the market at roughly the same integrated price:

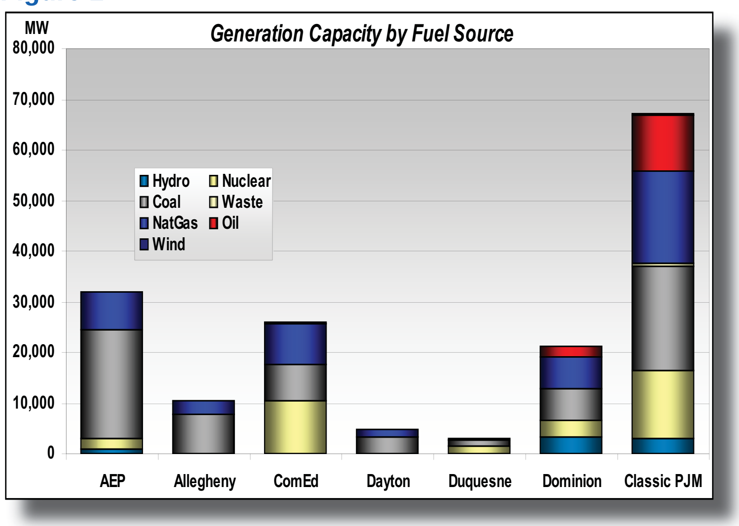
Type of plant	Capital cost ($/MWh)	Fuel/O&M ($/MWh)	Total ($/MWh)
Wind turbine	$45	$5	$50
CCGT	$8	$42	$50

Note: This is meant only as a high-level comparison. It assumes a $1300/kw capital cost for a wind turbine that has a 50 percent operating rate and a $5.00 O&M. The gas plant is a CCGT with a $500/kw capital cost and a 7,000 Btu/kwh heat rate at $5.40 gas and a $4.00 O&M.

In practice, however, PJM (and other competitive markets) have established separate procedures for determining energy and capital cost recovery (also known as capacity, installed capacity, and reliability prices). In the energy market, the price bid into the PJM process by the wind facility is likely to be zero; it will be a price taker at any price level because its variable costs are practically nil. In contrast, the natural gas plant will bid at a price at which it can pay for its fuel. When the gas price is assumed to be $5.40 (as in our example above), and the facility can convert gas into electricity at a rate of 7,000 Btu per kilowatt-hour (7.00 MMBtu/MWh), the minimum electric price the plant is likely to bid into the PJM energy market is $38/MWh.

Each of the PJM market areas brings with it a history of generation endowments: commitments to "legacy" pre-1990 nuclear and coal plants (which share with wind the characteristics of high capital and low fuel cost), hydro facilities (quite limited in PJM compared with other markets like California and TVA), older oil plants (often built in areas closer to the coast and more distant from the coal fields), and a very large infusion of new natural-gas fired plants. More than 95 percent of the new generation capacity built in PJM since 1999 was fired by natural gas.

Figure 1

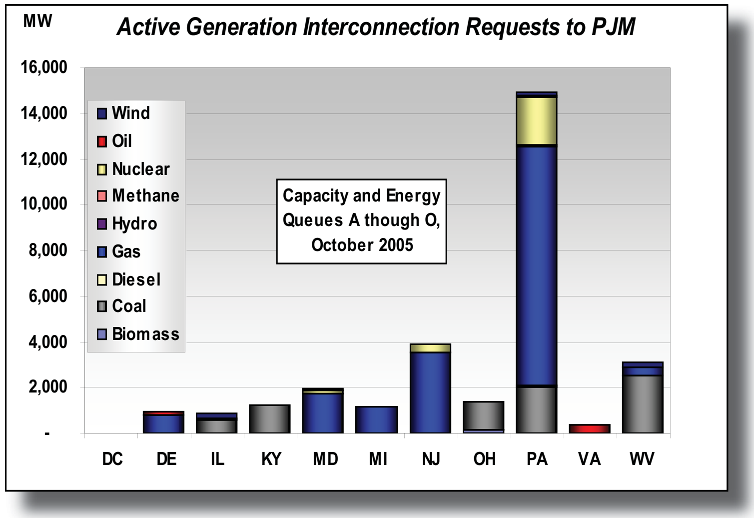


In spite of the recent (and since abated) surge of natural gas power plants in PJM, both the "classic" and "new" PJM areas relied extensively on coal for their baseload energy and capacity. Figure 1 presents a summary of the generation resources in both the "classic PJM" and its "new areas." In Classic PJM, hydro, nuclear and coal resources account for 37,000 MW of generation, 55 percent of total generation capacity. In the new areas, hydro, nuclear and coal resources account for 68,000 MW of generation, 70 percent of total generation. The diversity of fuel sources gives consumers in the new, larger PJM an energy market that reflects a variety of input fuels setting prices "on the margin of the market."

Additions to Generation Resource Endowment

With the addition of parts of Virginia, West Virginia, Kentucky, Ohio, and Illinois to the original PJM market areas comes a propensity for new generation requests to contain more coal plant interconnections. This offsets the propensity to build gas plants in New Jersey, Maryland, and eastern Pennsylvania, as seen in the chart below.

Figure 2



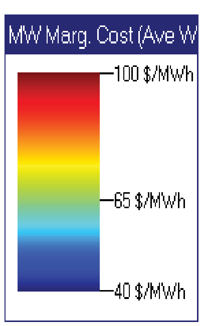
PJM is also seeing an enormous increase in the number of interconnection requests from wind projects. As of the end of September 2005, the 51 wind projects in the various PJM queues constituted more than 70 percent of all of the interconnection requests.

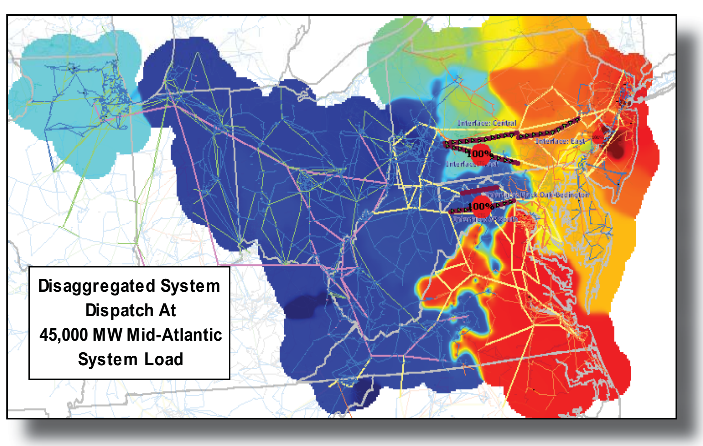
Applying The Economic Logic of Integration to PJM

In principle, the economic logic of integration is that the appropriate expansion of an electric market will yield benefits (a) as a larger number of generating units can be subjected to the optimal economic dispatch to serve load, (b) as the competitive struggle forces efficiencies in investment in both generation and transmission assets, and (c) as forward markets develop to provide hedging opportunities to market participants.

The expansion of the PJM RTO to include Allegheny Power, ComEd, AEP, Dayton, and Duquesne adds to the coal capacity of the PJM genera-

Figure 3





tion portfolio. This additional coal capacity in the west provides a low cost resource of energy that – given adequate transmission capacity -- can be accessed in the load centers in the east. Prior to the inclusion of the new areas into the PJM RTO, the elimination of through and out rates between PJM and MISO had already reduced barriers to trade flows from these western markets. The inclusion of the new areas into PJM allows the more efficient dispatch of generation in the larger market area, minimizing congestion and allowing the optimal flow of power from western sources. These changes should manifest themselves in market prices over time.

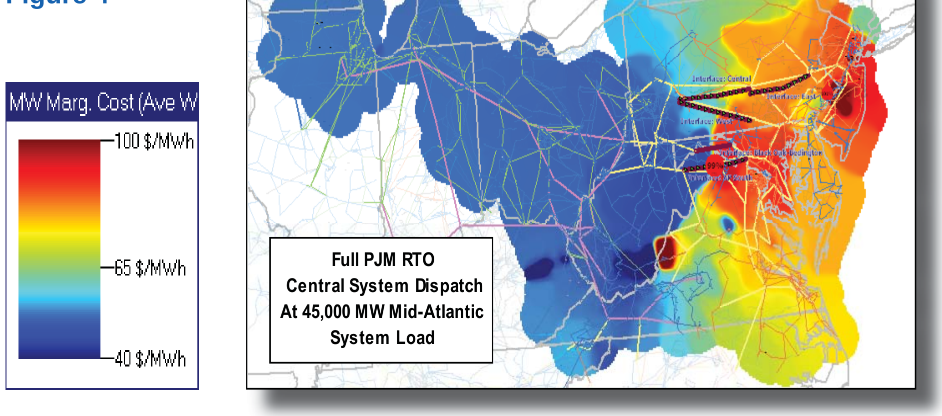
Price Effects of PJM Expansion As Measured by Powerflow Models

There are two ways of assessing the impact of PJM expansion on market prices. First, we can use engineering models of the power market to simulate the effects of market integration on energy prices at each node of the system, pre- and post-integration. The specifics of how this can be done are described in Appendix 1.

The effects of PJM's expansion are summarized in the "price contour maps" (Figures 3 and 4). These maps aggregate the energy price outcomes in two different market conditions: before integration between PJM and its new market areas, and after integration. By its very nature, the Powerflow model contains a representation of all of the transmission lines, generators, and load buses in each market area. Generators are dispatched according to a "security constrained" optimal dispatch at rates defined by a number of factors, most prominently including the price at which they bid in their energy, the capacity of each transmission line, and the level of demand from consumers.

The virtue of these Powerflow analyses is that they can be replicated by others using similar tools. The results of the model's analysis should not be surprising. At all load levels, the consequence of PJM integration is a reduction in energy prices for the region as a whole. Essentially, that reduction stems from the fact that there is surplus, relatively low cost energy in the West that should be (and in the model, is) shipped to the East. The centralization of

Figure 4



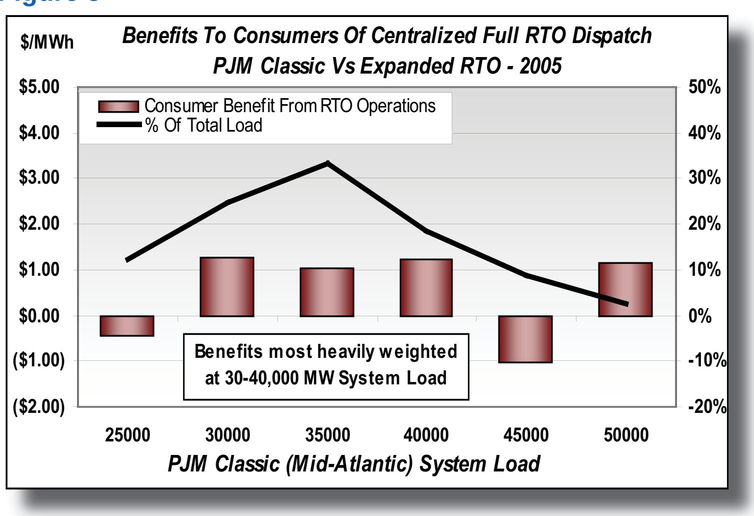
dispatch decisions and the elimination of transmission "seams" (transmission charges by each utility for power flowing across its borders) facilitate this increased flow in the Powerflow model.

The model also calculates prices at each node, and with those calculations it becomes possible to measure load-weighted average prices in each area, pre- and post-integration. The exact level of these prices is determined by a host of necessary assumptions, among which the most important is input fuels prices. The contour maps shown in Figures 3 and 4 reflect an array of input fuels prices (presented in detail in Appendix 1) that yields an energy price difference across a range of load levels of $0.78/MWh: that is, the price of energy across all of the regions of the expanded PJM market is $0.78/MWh lower post-integration than it was before integration.

We estimate electric energy consumption in 2005 in the expanded PJM market will be approximately 700 terawatt hours. As a result, a $0.78/MWh reduction in the area's energy price would result in energy savings for the region as a whole of approximately $500 million per year.[1]

The PowerFlow model indicates that the beneficial impact of integration makes itself felt across all of the various dispatch levels of the market, from relatively low to the higher load conditions (in the chart below, the total system load is represented by the Mid-Atlantic region load).

Figure 5



These are the savings any PowerFlow model with similar assumptions would project. Among the assumptions is that generators in the market will

[1] Electricity consumption is measured in watts (the power produced by a current of one ampere across a potential difference of one volt). Even in the United States, a metric system hierarchy is conventionally used to deal with size, thus 1,000 watts = 1 kilowatt; 1,000,000 watts = 1 megawatt; 1,000,000,000 watts = 1 gigawatt, 1,000,000,000,000 watts = 1 terawatt. If the PJM market area consumes 700 TWh, and the savings from integration are $1/MWh, then 700,000,000,000,000/($1 per 1,000,000) = $700,000,000 per year.

behave competitively (that is, bid energy prices into the market that reflect their marginal costs). To the extent this does not happen, actual market results would differ from this idealized, technical picture.

In the real world, therefore, the question is whether the PJM platform has accomplished the objectives of restructuring, i.e., subjected its participants to the "competitive struggle." If that is indeed happening, we expect to see increases in efficiency in energy pricing in PJM's central markets, and some convergence in efficiency indexes (to the extent allowed by existing transmission constraints) between PJM and its associated markets. Given the specifics of market design – particularly dividing activities into energy, capacity, and ancillary services markets – we must address each market in turn. We begin with the energy market.

Price Trends in PJM and Associated Markets

One of PJM's most significant features is its benchmark, "PJM Western Hub" energy price. We will be referring to that price repeatedly in the pages that follow. As has happened in other energy markets, trade in the PJM market has coalesced around this single index, which is an aggregate of a series of buses in the original PJM market.[2] Market participants are now accustomed to trading "PJM Western Hub" as the central instrument reflecting system-wide market fundamentals, and then managing their regional and local risks (or price differences between the market of greatest interest to them and the PJM Western Hub), through other instruments that we will discuss later.

On-Peak Price Trends

We start with a simple review of energy prices, beginning with the on-peak prices (from 7AM to 11PM on weekdays). Figure 6 shows the overall price increase trends in PJM and surrounding areas that are consistent with fuel price increases. There is a general trend towards price convergence between the regions. This trend is more clearly defined in Figure 7 which highlights the narrowing price differences between PJM, Ontario and ComEd.

Price swings from highs to lows are following a generally decreasing trend that is difficult to see in Figures 6 and 7. This decrease in the magnitude of the price swings is an important indicator of a decrease in market volatility. This trend can be seen more clearly in Figure 8 which shows the absolute value of the price difference between the monthly average on-peak price and the 12 month moving average (trailing). From mid-2001 to mid-2005, there is a clear decrease in the deviation of monthly prices from the 12 month moving average. This decrease in volatility provides a significant contribution to promoting liquidity in the PJM markets.

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[2]In the crude oil market, trade has coalesced around "West Texas Intermediate," a type of crude oil produced largely in Texas; in the natural gas market, trade centers around the "Henry Hub" contract, which is a geographic center for physical natural gas trade in Louisiana.

Figure 6

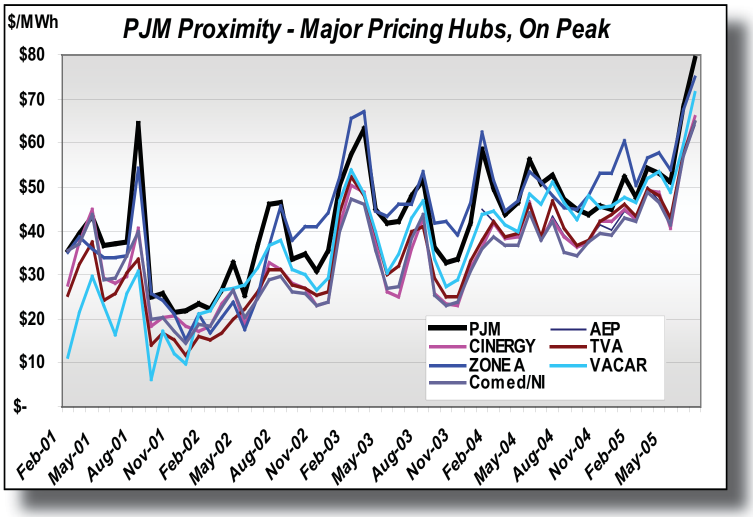


Figure 7

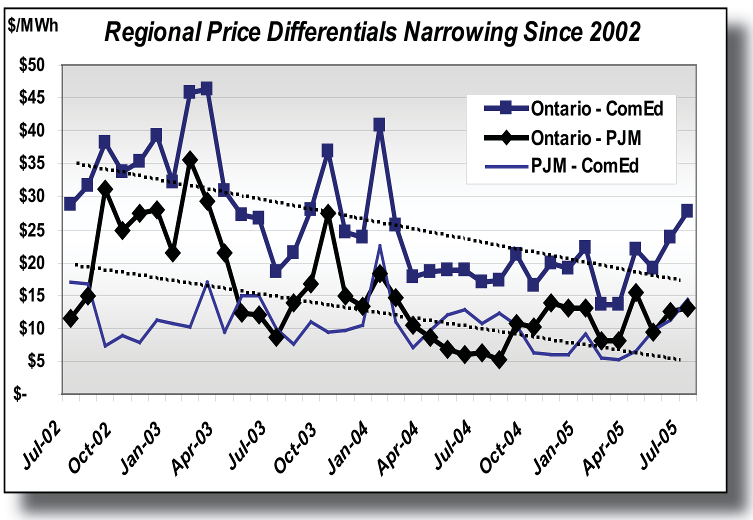
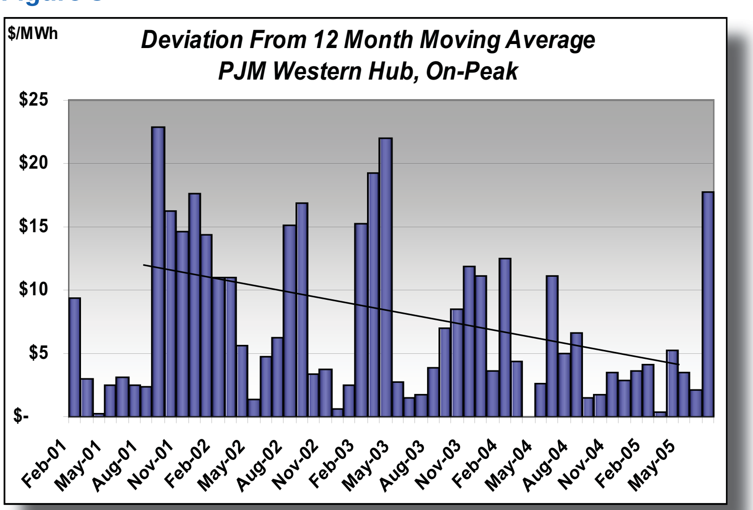
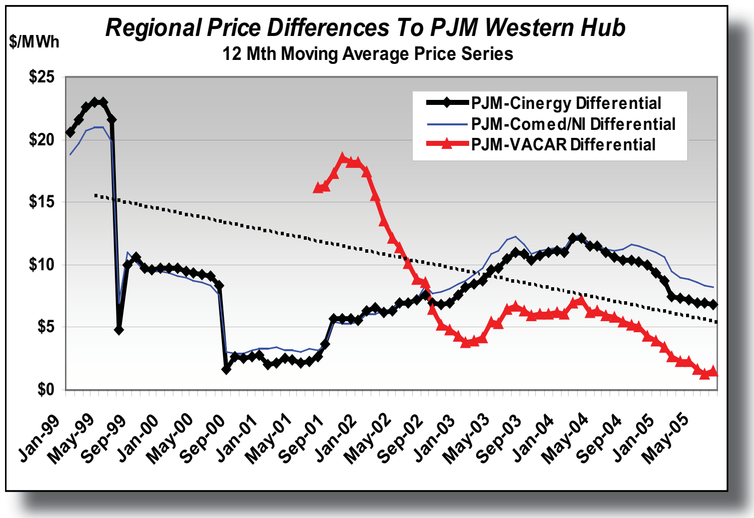


Figure 8



Price convergence is more apparent when smoothing price swings with the 12 month moving average. Figure 9 shows the absolute value of price differentials between PJM and Cinergy and between PJM and VACAR (Dominion). The PJM-Cinergy price difference shows a dramatic decline from 1999 to 2001 and an overall decreasing trend. The PJM-ComEd/NI price differential shows a similar pattern. The PJM-VACAR differential shows a remarkable convergence from above $15.00 to well below $5.00/MWh.

Figure 9



These trends – decreased volatility in power prices in spite of increased volatility in natural gas prices, and an apparent convergence of price trends between neighboring markets – need to be examined not only in terms of absolute prices but also in terms of heat rates. We examine heat rate trends later in this section.

Off-Peak Price Trends

ESAI has also analyzed the pricing trends for the off-peak periods for PJM and the surrounding major trading hubs[3].

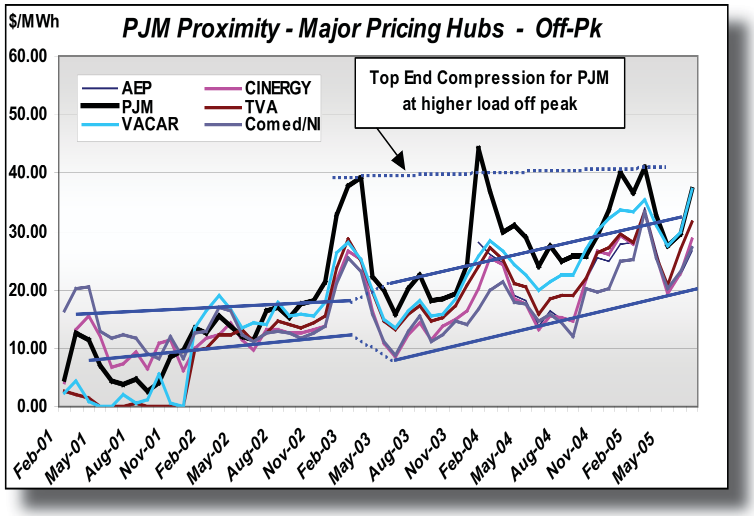
Figure 10 shows two interesting trends:

1) Price Divergence - the price spread between the various pricing hubs was quite narrow during the period 2001 to 2002. However, from early 2003 to 2005, the price range between the Hubs widens.

2) PJM Winter Price Caps - the volatility of PJM prices has increased due to the high price of off-peak power during the winter periods starting in 2003. However, the magnitude of the peaks has not increased.

[3] Note that there are fewer trading hubs for which off-peak prices are quoted.

Figure 10



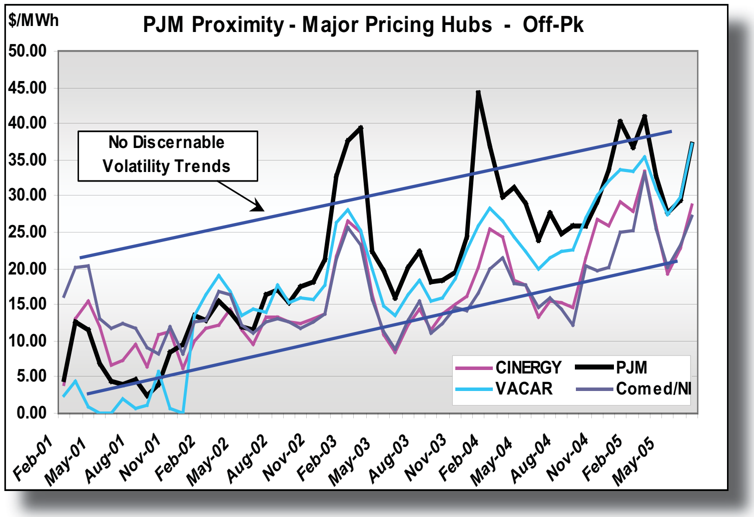
PJM off-peak prices have been drifting higher relative to the other hubs. We note that increases in PJM off-peak loads are increasingly being met by gas-fired units. This is especially common during the early and late off-peak hours – the transition period to and from the on-peak hours – when gas fired units often set price. Also, low priced power from the western areas of PJM (and imports from the west) tend to bind the internal west to east interfaces, which can cause congestion and provide support to the PJM Western Hub pricing index. The adjoining hubs will tend to see prices remain steady as PJM's import capability during the off-peak hours is limited by the binding internal transfers.

The influence of gas on PJM off-peak pricing is clearly seen during the winter months. Off-peak loads remain strong during the winter, as heating demand does not rest at night. CCGTs are generally dispatched to meet the higher winter off-peak demand and as such, wintertime off-peak pricing is increasingly influenced by gas prices (load grows, but base load coal and nuclear capacity remain stable or decline – gas fired units take up the slack).

As PJM increased its dispatch of gas fired units during off-peak hours, marginal costs increased accordingly (given that gas prices were rising during this period). Steadily increasing gas prices relative to coal result in higher off-peak prices in PJM relative to the other hubs. This trend is likely to continue in the near to medium term given the strong natural gas fundamentals – both temporary from recent hurricane damage, but also structural, due to the lack of excess production capacity.

While PJM winter off-peak prices showed higher volatility due to increased exposure to gas prices, the overall volatility of the regional hubs does not exhibit any particular trend. We can broadly define volatility for these graphical representations as the difference between the highest highs and the lowest lows – the greater the difference, the higher the volatility. Figure 11 indicates that volatility in 2003-2005 is not significantly different than seen in 2001.

Figure 11



Although on-peak price volatility has been declining significantly, off-peak price volatility has been constant or slightly increasing due to the increased influence of gas pricing in PJM. This is largely due to the relative stability of coal prices, which are the ultimate driver for off-peak pricing. In addition, the load profiles during the off-peak periods tend to be much more steady and predictable than the on-peak load profiles.

On Peak Heat Rate Trends

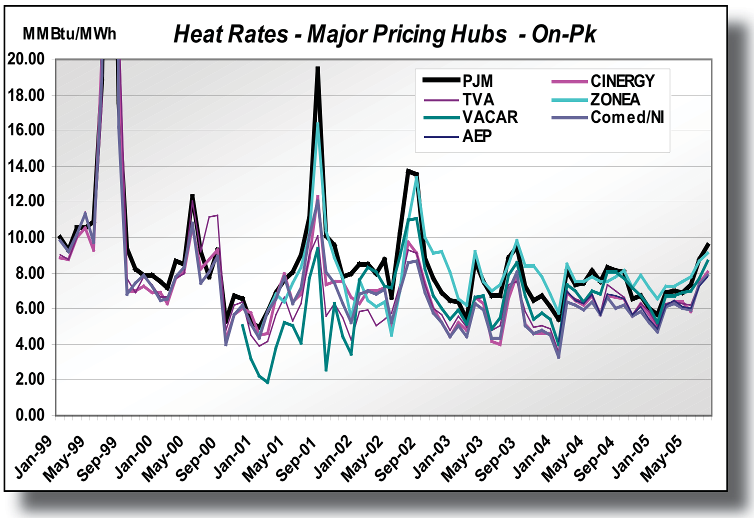
Studying pricing trends provides some interesting insights into the electric markets. However, because there are many external factors that influence the price of power beyond the mechanics of efficiently operating the grid, it does not always make sense to study price trends alone. For example, many consumer advocates point out that electric power prices are higher now than before de-regulation was implemented. This is true, but natural gas, coal and oil prices have increased radically over that time, pushing electricity prices directly higher as a result. These higher prices for electricity would have come with and without deregulation.

Therefore, the more pressing question is whether electric markets under PJM's market design and expanding footprint have become more efficient. We address this question by studying the market heat rate trends in PJM and adjoining markets.

We convert PJM and other areas' energy prices into "implied market heat rates" by dividing the market price by the price of natural gas. In that way, we can make a comparison of power prices normalized by the natural gas price. In other words, prices can be compared without the influence of highly fluctuating natural gas prices. In generator terms, the heat rate reflects the efficiency of the unit. An efficient combined cycle gas unit can produce power at a rate of 7,000 Btu/kwh or 7.0 MMBtu/MWh. A less efficient gas fired steam unit may require 11.0 MMBtu to produce the same MW of power. The market heat rate provides insight as to where on the spectrum of efficiencies the market is operating.

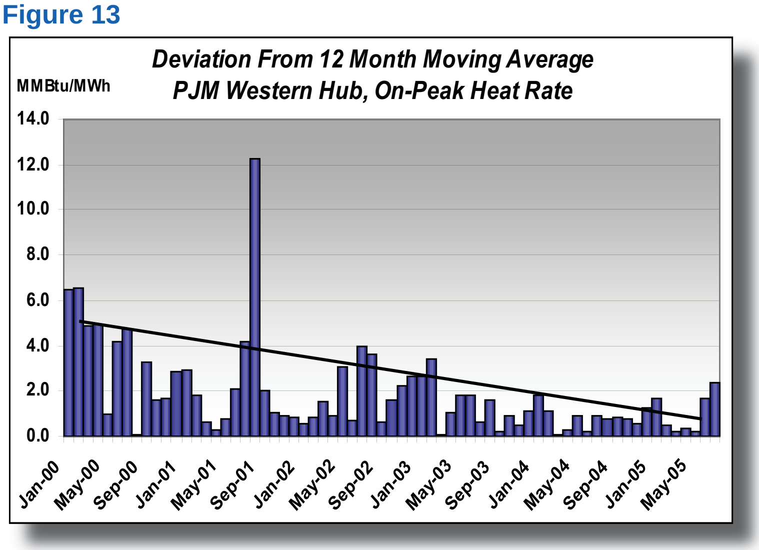
To use this metric properly in an analysis of market trends, we have to make note of the markets' initial generation endowment. As the charts indicate, in the late 1990s PJM and Cinergy both experienced a series of power price shocks that sent their market heat rates to levels above 20 MMBtu/MWh. Over the next five years, the very substantial increase in generation capacity – most of it natural gas – lowered the on-peak market heat rate from these very high levels to the 6 to 8 MMBtu/MWh range.

Figure 12



Finally, the heat rate chart in Figure 13 also shows that the volatility of heat rates is decreasing. The monthly deviations from the 12 month moving average are used to illustrate the volatility. This trend is also a side effect of the increase in trade, and may also be caused by substantial increases in the liquidity of the day-ahead markets (which this chart reflects). There are indications that the amount of energy cleared in PJM's day-ahead and real-time markets has increased from less than 20 percent when the market was formed to as much as 70 percent in 2005. Such dependence on short-term markets is acceptable as long as there is sufficient uncommitted capacity in the market

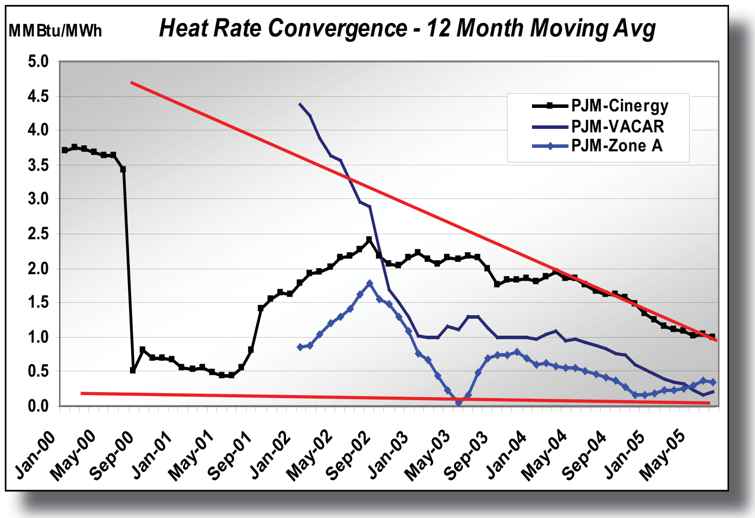
Figure 13



to meet swings in demand. As PJM and the neighboring markets use up their large surpluses of generation, we should expect the market heat rates seen in the chart above to begin to increase.

In addition to this decline, market heat rates in the PJM, Cinergy and VACAR (Dominion) areas also appear to be converging, Figure 14. As we shall see later in this report, this is an additional expected outcome from increases in trade between the regions, which is one of the principal objectives of the expansion of PJM.

Figure 14



Off-Peak Heat Rate Trends

Off-peak prices have moved higher with increases in coal and natural gas costs, but off-peak implied heat rates have remained very stable over time in PJM as a whole. Figure 15 shows that off-peak heat rates have been relatively stable from 2002 to 2005 for PJM and surrounding areas.

Figure 15

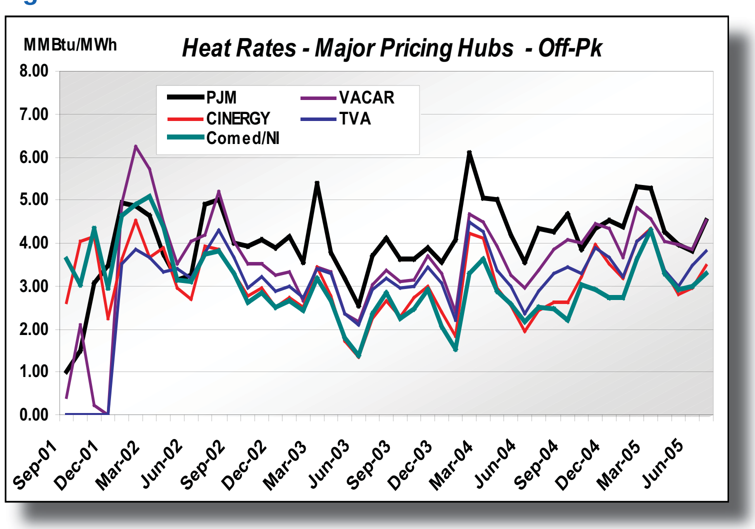


Figure 16 compares the off-peak heat rates in PJM and ComEd. ComEd heat rates have trended higher after integration, suggesting that flows from ComEd to PJM have increased. It is interesting to note that from May to September of 2004, there was little change in the ComEd off-peak heat rate. However, from October 2004 onwards, there appears to be a significant rise in the heat rates. This is most likely due to the restricted flows through the AEP territory (about 300 MW) from ComEd to PJM between May 2004 and September 2004. When AEP joined in October, these restrictions were lifted and greater flows from ComEd could be realized.

Figure 16

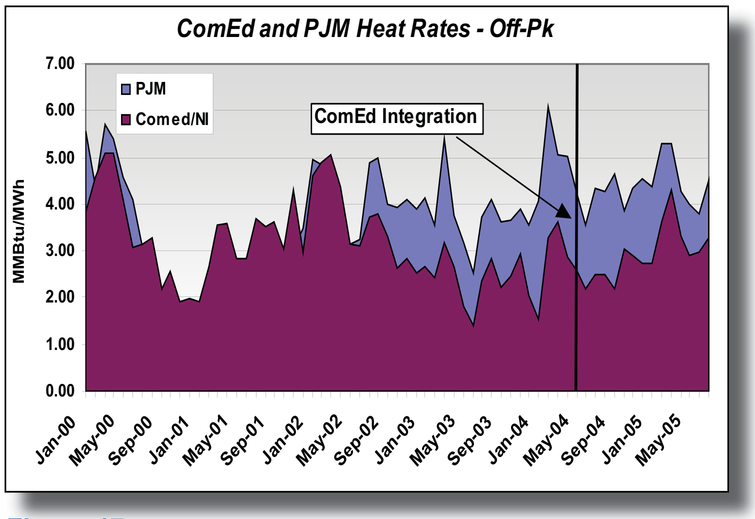
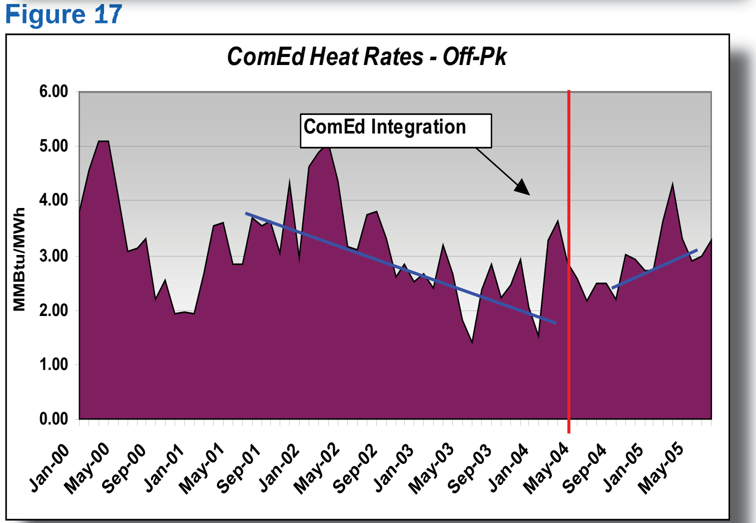


Figure 17

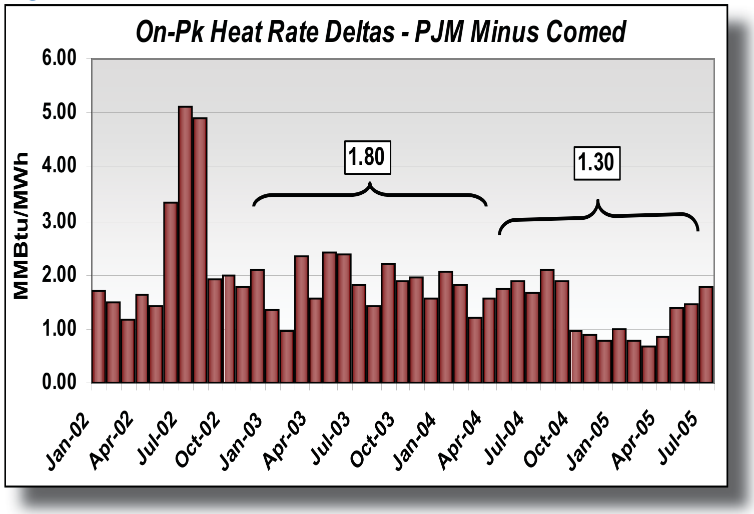


Heat Rate Effects from Joining PJM: An Introductory Comment on PJM Zonal Pricing, Basis Risk, and FTRs

When a new area joins PJM, we should expect the heat rates of the markets to begin to converge as participant seek trade opportunities within the larger market. Commonwealth Edison joined the PJM market in early 2004. Prior to that date, the heat rates differences between the markets – as seen in Figure

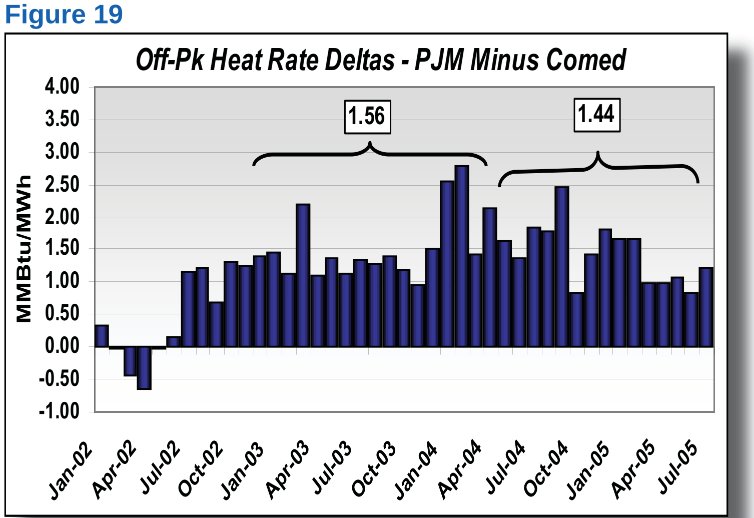
18 below – averaged 1.8 MMBtu/MWh. As integration was implemented, the heat rate differences diminished sharply. In the winter of 2004-2005, they were typically below 1.0 MMBtu/Mwh, and for the period June 2004 to June 2005 the difference averaged 1.3 MMBtu/MWh.

Figure 18



These changes in heat rates gradually become absorbed into the expectations of market participants. Instead of the hyper-volatility of the 1999-2001 period, in which participants in each market had to be cognizant of the peculiarities affecting energy prices in that small market, current PJM market participants will be able to develop views on the central price of one mega-market indicator, that of PJM.

Figure 19



Conclusions: Signs of Competitive Struggle in the PJM Energy Markets

As we noted at the beginning of this analysis, the expectation of the PJM market design is that it would bring the competitive struggle to electricity trade. Given the expansion of PJM, we need to look for signs of this struggle both in PJM's central market – PJM Western Hub – and in its associated markets as new areas are absorbed.

Our review of heat rates – the best measure to use given the radical changes in the price of natural gas – clearly indicates the competitive struggle in PJM. Companies that have built new CCGTs have seen the market heat rate of PJM Western Hub decline from an average of over 11.0 MMBtu/MWh in 1999 to 7.3 MMBtu/MWh in 2004. At these 2004 levels, the competitive struggle is intense indeed, since new CCGT facilities will find it virtually impossible to earn a profit in the energy side of the PJM market.

This difficulty of making a profit in the energy side of the business is an expected consequence of the operation of market forces: generation investment in PJM in the 1999 – 2003 period was in excess of the immediate and short-term needs, and operating margins have fallen accordingly. This is not, however, the end of the competitive struggle analysis – as we have noted – the capacity markets are also providing clear indications of this competitive struggle.

We also examined energy prices in the associated markets of PJM – Cinergy, VACAR, and ComEd. We expect integration to cause some increase in convergence in heat rates in those markets. The exact extent of convergence depends on the capacity of the transmission system (the more constrained, the less convergence). We have shown that there are indeed signs of convergence, which we interpret as the PJM platform conveying the competitive struggle to each of the associated markets as PJM's centralized dispatch and the better use of transmission facilities are implemented.

The Management of Regional Price Risks: FTRs

Whether we are referring to the original or the expanded PJM footprint, it is to be expected that the transmission system cannot enable all areas to experience the same energy prices all of the time. The cost of input fuels, the type of generation, the levels of demand growth, and many other factors combine to make market-determined energy prices vary from node to node, and from region to region in dynamic ways. Such pricing differences are essential market forces, which PJM's locational pricing framework brings forth on a real-time and hourly basis.

Over measured increments of time – hourly, daily, weekly, monthly and annually – the effect of these pricing differences is referred to as "congestion" because limitations in the transmission system prevent energy flows from equilibrating energy prices in PJM all of the time. Thus, in some hours/days/weeks/months/years, one area of PJM will experience higher prices than other areas. Some of these congestion costs were essential characteristics of the transmission system at the beginning of PJM's formation, others are the result of dynamic forces that have emerged more recently, and still others are the result of forces that are foreseen in PJM's studies of future market changes.

In this system, “firm transmission customers” are those that originally possessed or have been willing to acquire PJM energy and capacity (or reliability) services on PJM’s most secure basis. This firm service provides the highest level of PJM assurance of delivery, but it does not protect these customers from increased costs due to transmission congestion.

Financial Transmission Rights, or FTRs, are the mechanism that the PJM market offers to manage the “basis risk” (or the risk that local or regional price differences will change) caused by periods of transmission congestion. In principle, with FTRs, risk-averse market participants can enter into long-term supply contracts and purchase FTRs to become indifferent to the hourly local energy price values. FTRs can be seen as an adjunct to the PJM energy market, and are subject to their own supply and demand dynamics because they are bought and sold, both in bilateral transactions and in their own PJM-administered auctions.[4]

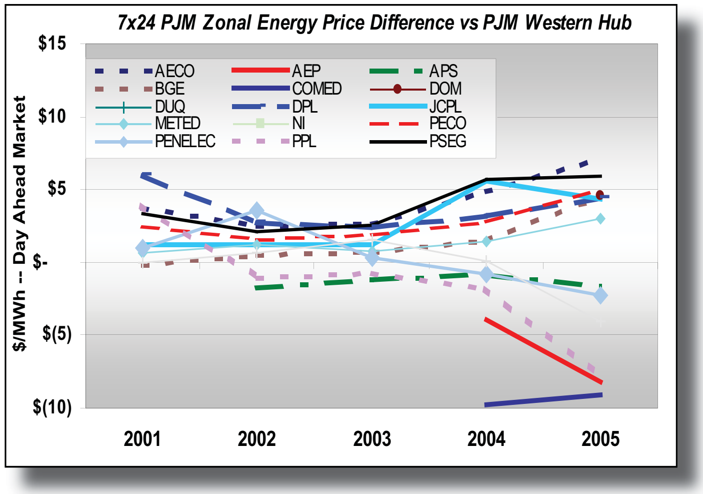
The efficacy of FTRs, therefore, is an important issue for both old and new market participants. Ideally, FTRs facilitate the competitive struggle and allow market participants with different risk appetites to absorb or shed the amount of regional pricing risk they desire. As was the case in our analysis of energy prices, we would expect to see positive signs of the competitive struggle in the volume of FTRs traded and in a lack of bias in FTRs results.

Financial Transmission Rights

The starting point for this analysis is to review the zonal energy pricing differences for the PJM market areas from 2001 up to August 2005. Figure 20 presents one compilation – the “basis” between each zone and the PJM Western Hub index for all of the hours on an annual average basis. It indicates that the eastern markets – Jersey Central Power and Light (JCPL), Public Service Electric and Gas (PSEG), Atlantic Energy (AECO), and Baltimore Gas and Electric all show rising congestion from 2003 levels, when all PJM regional markets had lower congestion. On the other side of the congestion divide, the American Electric Power and Commonwealth Edison markets entered PJM with “negative congestion,” with average zonal prices below those of the PJM Western Hub.

[4] FTR contracts are traded by auctions conducted by PJM. Auctions are conducted for annual contracts in four rounds held in March and April. Monthly auctions are held for available entitlements not sold in the annual auctions. PJM also facilitates a secondary market for bilateral trading. Settlements for the contracts are based on the daily average Day Ahead Market LMP differences between the contract source and sink points (congestion revenue). The net revenue received by a participant that owns an FTR contract equals the total congestion revenue determined in the Day Ahead Market settlement minus the the cost of the FTR purchase. For example, if a trader buys an FTR from the PJM Western Hub to JCPL at a cost of $2.00/MWh and the final settlement price is $5.00/MWh, the trader receives a net revenue of $3.00/MWh which offsets his increased costs of transfers. For more information on FTRs, see PJM Manual 6.

Figure 20

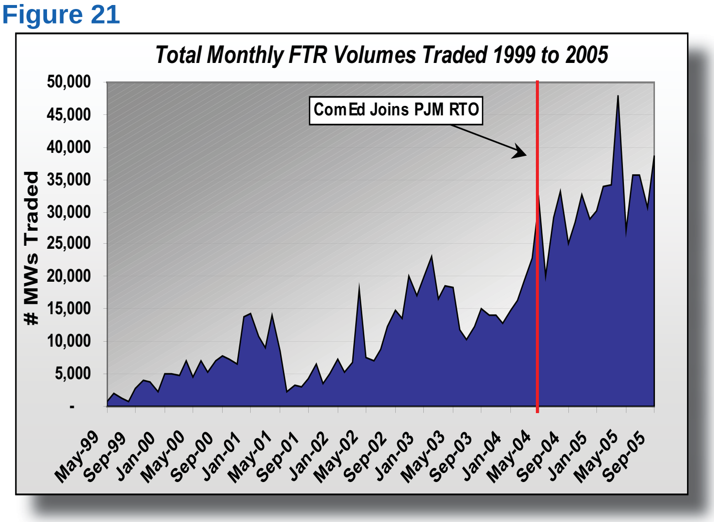


The evolution of congestion illustrates one of the founding principles of PJM: changes in congestion reveal changes in the fundamentals of electricity, and because PJM has a larger footprint than an individual utility, consumers have some ability (defined by the optimized capacity of the transmission grid) to demand energy and capacity from different parts of the market. Thus, the rapid increase in natural gas prices in 2004-2005 naturally caused an increase in demand for lower-cost electrons from PJM's coal-oriented regions. That demand can exceed the ability of the transmission system, and due to the limits of the transmission system, consumers in gas-oriented regions had to buy more expensive power and producers in coal-oriented regions had to sell less expensive power in their respective areas.

The role of FTRs in this dynamic is to give market participants a way to hedge or manage these changes in energy prices. To the extent that they own or can obtain financial transmission rights between PJM's nodes and zones, and to the extent that these rights are reasonably valued in the FTR marketplaces, market participants can hedge the effects of these energy price changes.

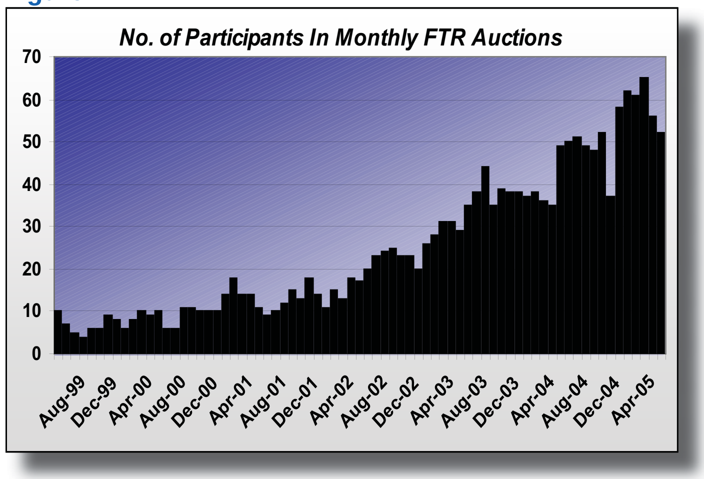
The focus of this Report, however, is not on the mechanics of the FTR market, but is instead on the overall efficacy and liquidity of that market. Figures 21 and 22 show the results of that analysis, indicating that the volumes

Figure 21



of FTRs traded in PJM's markets have risen from a few hundred megawatts when the market was launched in 1999 to well over 30,000 megawatts in most months of 2005. The number of participants has similarly risen from less than 10 in 1999 to more than 60 in 2005.

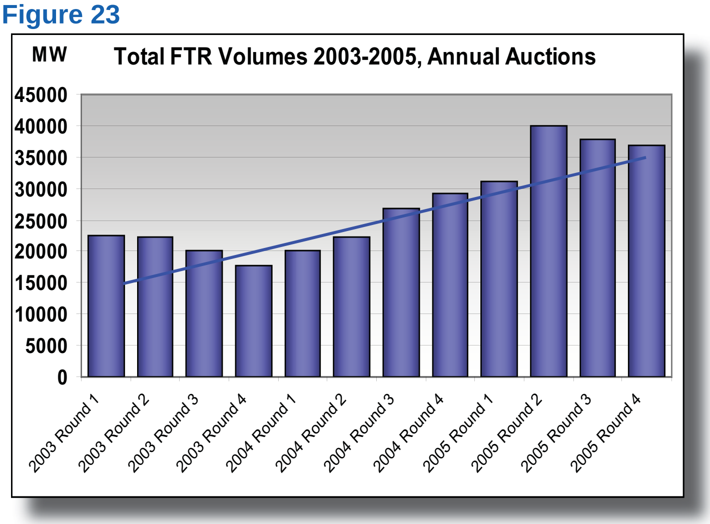
Figure 22



This increase in both participants and volume indicates a marked increase in the depth and liquidity of the FTR market. Typically, the number of bids submitted is about 10 times higher than the bids cleared, which is also indicative of the interest in this market and the depth of participation.

These increases in FTR trading volumes also indicate that a growing amount of energy in the PJM market is being settled in the day-ahead and real-time markets, which in turn is an indication of the relatively low volume of longer-dated trades that have been taking place in the constrained 2003-2005 power market financing environment, which we discuss later in this report. Given these financial realities, a robust FTR market in which market participants have confidence is an enormously important asset in the overall PJM market design. We will show in a subsequent section that this confidence is borne out by indications that FTRs do provide an unbiased market for hedging locational price risks.

Figure 23



VI. Electric Trade Effects of Integration

One of the purposes of PJM's expansion is to stimulate increases in electricity trade. ESAI has conducted a study of the change in transfers between PJM and the recently merged market areas to determine the extent to which PJM has facilitated increases in trade. Prior to integration, the transfers with an outside area were identified as an external transfer or external interface. The interface nomenclature accounts for the fact that the transfers between PJM and a specific area can occur over multiple lines connecting the areas. PJM tracks and posts external interface data on an hourly basis.

After integration, the transfers across the interface were subsequently regarded as internal flows and this flow data was no longer posted by PJM. A new set of external interfaces was defined by PJM consistent with the new RTO borders which are now monitored and have posted data. With the 'internalization' of the previously external interfaces, the transfers between the newly merged area and the pre-integration PJM configuration were no longer monitored. Therefore, comparing transfers pre- and post-integration posed a significant challenge.

ESAI worked with PJM staff to develop data sets of the metered flows across the individual lines that make up each of the external interfaces for the areas prior to integration. These metered flows were aggregated to develop metered interface flows, which could then be compared on a pre and post integration basis.[1] We were not able to do a similar study for the Commonwealth Edison transfer flows because ComEd never had a contiguous interface with PJM prior to integration.

The following charts and analysis represent the culmination of this intensive data gathering effort and provide useful insights into the changes in transfers that can be attributed to the merger of new areas. We conclude that:

1. In general, transfers with the merged areas have increased post-integration. This is a reflection of both the optimization of dispatch and the increased opportunity for trade within the RTO.

2. Transfers between AEP and PJM increased notably post integration. Transfers with the neighboring (but not integrated) First Energy area did not increase.

[1] The metered flows across the interface will not necessarily match the external interface data tracked prior to integration. The tracked external interface data represent only ***scheduled flows*** whereas the metered interface flows developed by ESAI represent ***all power flows***, including loop flows. ESAI has used the metered flows both before and after integration to ensure an equal comparison.

3. Transfers with Allegheny Power continue to increase over time.

4. While it is early to draw firm conclusions about transfers between Dominion and PJM, early data indicates that net transfers to Dominion have changed dramatically. This is a reflection of lower local dispatch within Dominion and a corresponding higher level of imports from the rest of PJM.

Allegheny Power Integration Transfer Impacts

The Allegheny zone (AP) covers a major portion of West Virginia as well as small portions of Western Pennsylvania, Maryland and Virginia. This area is rich in lower cost coal generation. Since integration in April 2002, transfers between AP and PJM Classic, now the Mid-Atlantic zone, have increased significantly.

Figure 1

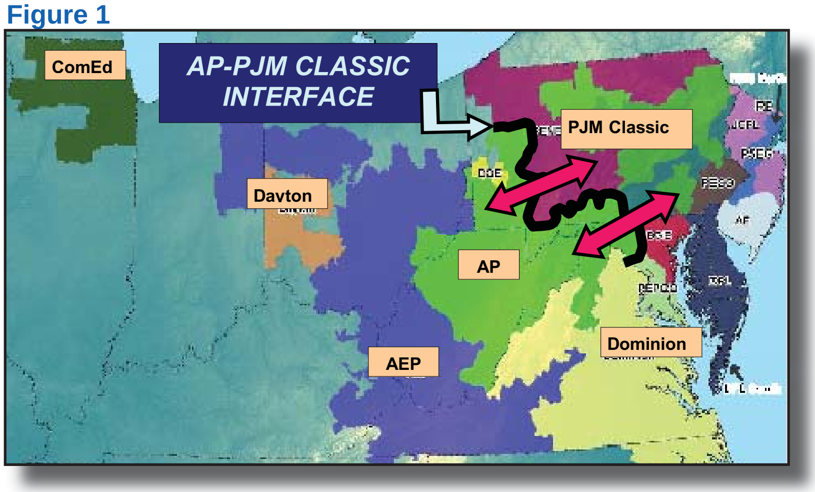
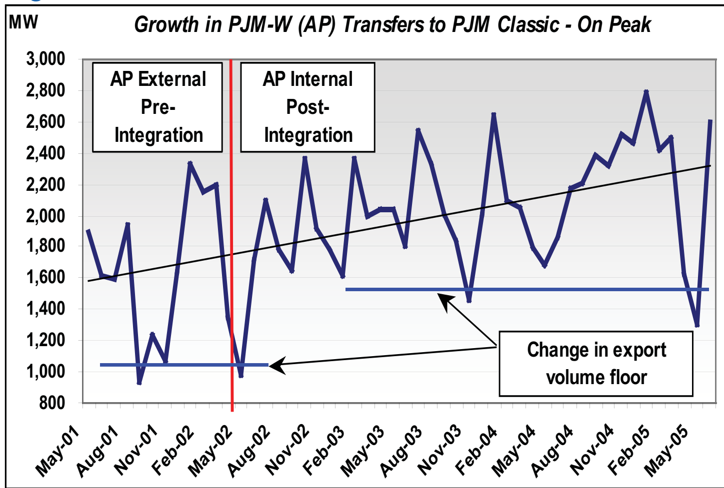


Figure 1 displays the interface between Allegheny Power and PJM Classic. In the year preceding the Allegheny integration, on-peak transfers averaged 1,700 MW from Allegheny to PJM and ranged from 1,000 MW to 2,200 MW. Figure 2 shows the metered interface flows from AP to PJM from May 2001 to June 2005. The data display a clear trend of increasing transfers over time. In the more recent period from January 2004 to June of 2005 on-peak transfers averaged 2,200 MW, an increase of 500 MW.

Transfers from AP to the Mid-Atlantic (PJM Classic) area are limited by transmission constraints at the AP South and Bedington-Black Oak interfaces. Upgrades identified in PJM's RTEP will increase the transfer capabilities of these internal interfaces, particularly at Bedington-Black Oak. This will allow further increases in transfers from AP.

Figure 2



AEP Integration Transfer Impacts

The American Electric Power (AEP) territory covers a number of utility areas to the south and west of the Allegheny Power area. AEP covers parts of western Virginia, eastern Kentucky, Ohio, Indiana and Michigan. The AEP service area is also rich in coal generation resources, with AEP being an industry leader in the advancement of coal generation technologies.

Figure 3

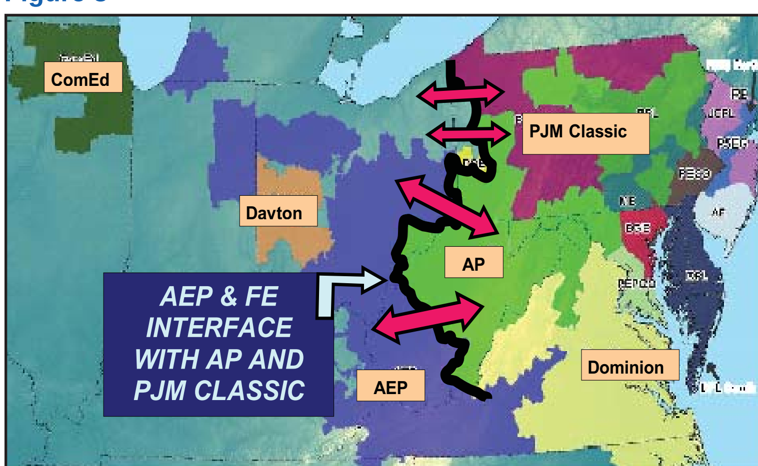
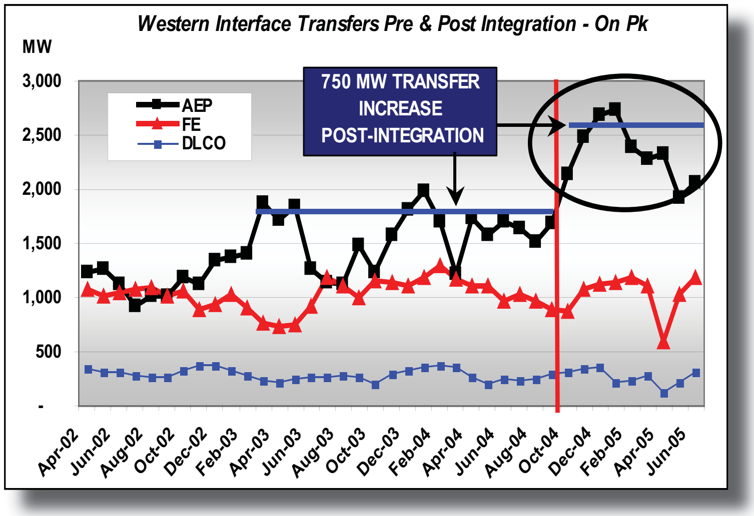


Figure 3 provides a representation of the PJM Western Export interface, as it existed prior to the AEP integration. Prior to the AEP integration (January 2003 through September 2004), on peak transfers averaged 1,550 MW from AEP to PJM. Post-integration transfers have averaged 2,300 MW, an increase of 750 MW, (see Figure 4).

It is interesting to note that the First Energy transfers to PJM did not exhibit any significant change during the AEP post-integration period. A review of scheduled transfers with FE indicates that transfer flows can exceed 2,000 MW in either direction. This suggests that the potential for increases in transfers exists but did not materialize. This indicates that the AEP transfer increases are attributable to the merger with PJM.

Figure 4



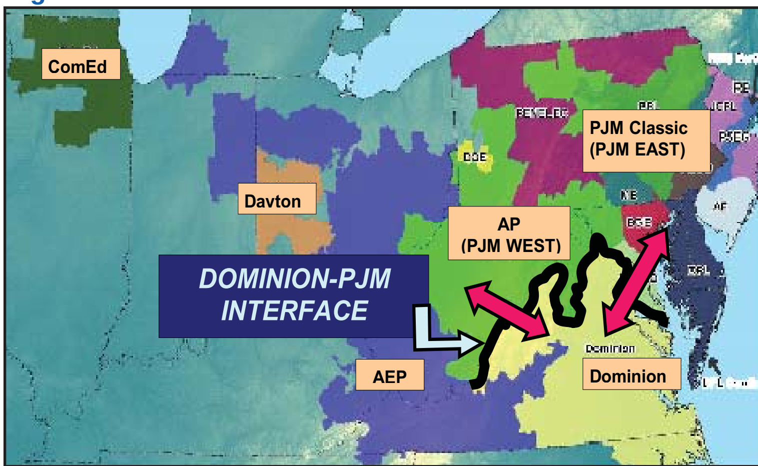
Dominion Integration Transfer Impacts

The Dominion service territory covers most of eastern Virginia and eastern North Carolina. The Dominion generation portfolio is very diversified with strong base load capabilities in nuclear and coal as well as having depth in efficient combined cycle gas fired generation and simple cycle peaking units fired on gas or oil. Dominion has some hydro generation capability as well as over 1,500 MW of pumped storage capability that can meet peak demand needs.

During on-peak periods, Dominion relies heavily on the gas and oil portion of its generation portfolio to meet its regional demand. While Dominion has a diverse generation portfolio, it remains more dependent on natural gas and oil than its neighbors to the west. Due to the high prices of natural gas and oil as well as strong regional load growth, on-peak energy prices in Dominion often rival or exceed those seen in the eastern Mid-Atlantic zones PSEG and JCPL.

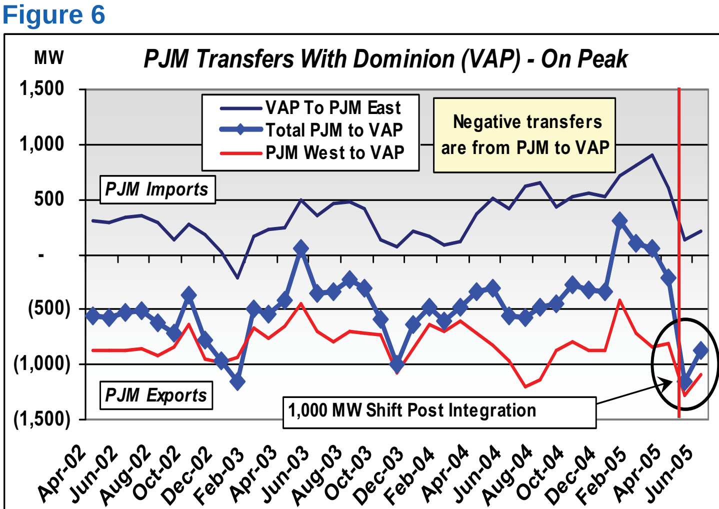
Dominion's integration into the PJM RTO facilitates imports and exports consistent with the relative merits of Dominion's fleer within the larger PJM generator stack. Figure 5 below shows the Dominion and PJM interface that has now become internalized within the PJM RTO.

Figure 5



Typical historical on peak transfers between Dominion and PJM involved flows from Allegheny Power (PJM West) to Dominion and flows from Dominion to PJM Classic (PJM East or Mid-Atlantic). Figure 6 provides the historical flows between these areas and shows the dramatic shift in flows as Dominion became integrated into PJM in May 2005. These interface flows are metered flows across the lines that comprise the interfaces to Allegheny (PJM West) and PJM East.

Figure 6



Compared to the first four months of 2005, May and June net flows increased into Dominion from PJM by 1,000 MW. This increase in transfers from Allegheny Power and the corresponding decrease in transfers to PJM East are directly reflective of changes in the operation of Dominion's assets expected upon integration into the PJM RTO. The two months of data should not be viewed as a 'startup anomaly' but rather a confirmation of the changes expected under the integration.

ESAI's powerflow models predicted similar trends when comparing the dispatch of Dominion's generation assets pre- and post-integration. Using a typical summer on-peak scenario (PJM Mid-Atlantic loads at 45,000 MW), Dominion would dispatch just over 15,000 MW of local generation to meet its demand operating outside of the PJM RTO. Typical historical import/export flows were considered in the model. When aggregating Dominion and the other newly merged areas into the current PJM RTO configuration, the Dominion local generation dispatch drops by over 1,000 MW and prices in Dominion fall by over $10/MWh. The drop in local generation is due to increased flows into PJM, consistent with the transfer behavior exhibited in Figure 6 above.

Conclusions

These changes in pre- and post-integration power flows are what any technical powerflow program would project, and yield precisely the economic benefits that we have been discussing throughout this report.

For the areas that increase their imports, the flows from PJM typically provide not only lower-cost power, but also often a welcome diversification in the portfolio of power sources.

For the exporting area, the increased flows represent economic opportunity to expand production. At first, that will primarily come in the form of higher utilization rates. As generators in exporting areas perceive they have greater opportunities to sell energy and capacity outside of their traditional borders, we expect to see them build new capacity, promoting economic growth in their market areas and increasing the overall supply of their products both inside their traditional area and into the larger PJM.

Finally, the measurements we have made in these pages indicate immediate changes in transfers across what used to be PJM's borders. The capacity to increase flows between what are now internal boundaries is certain to increase as PJM applies its five year (and beyond) Regional Transmission Expansion Plan across the larger area. PJM has already identified one conceptual project – *Project Mountaineer*-- that could increase the West to East transfer capacity by up to 5,000MW.

Whether or not the particular expansion identified in the early *Mountaineer* discussions emerges, it is clear that PJM provides a regulatory, contractual, trading and planning framework that is likely to result in even more electric trade in the future, to the benefit of all the areas of PJM.

VII. Afterword: Innovation Efficiency

There is a large amount of evidence and analysis on the effects of restructuring and deregulation on the U.S. economy. To some extent, there is still disagreement about the scale and scope of benefits to consumers from restructuring airlines, telecommunications, road carriers, and banks. But by and large, expert opinion agrees that "deregulation's net benefits to consumers are substantial . . ." As Clifford Winston, Senior Fellow in Economic Studies at the Brookings Institution has argued, "industries are likely to behave quite similarly when it comes to adjusting to deregulation, and that their adjustment, while time-consuming, will raise consumer welfare—significantly even at first, and increasingly over time. Markets will become more competitive. Firms will develop innovations to become more efficient and more responsive to consumers. The benefits to society will grow as the adjustment continues." [2]

Surveys in the scholarly literature on the effects of restructuring and deregulation provide a variety of estimates of the effects. In the surface freight transportation sector, for example, MIT's Paul Joskow shows that "service quality improvements and service quality differentiation has been a key feature of the evolution of these transportation sectors post-deregulation, " and that "the adoption and rapid diffusion of CCGTs was stimulated by allowing competitive entry into electricity generation." Those examples lead Joskow to propose an important "lesson learned" from restructuring: "too much emphasis on static efficiency gains or losses and not enough emphasis on the factors influencing the rate and direction of product and process innovation which are likely to have much larger consumer welfare effects."[3]

In a very real way, PJM has been an engine of innovation ever since the very first market design meetings were conducted. From the original conception that electricity could be subject to spot pricing like other commodities (albeit with very important market design characteristics to account for its unstoreability and interconnectedness), to the elaboration of those ideas into a Tariff, to the management of what became an enormously large interconnection queue, to the incorporation of workable rules for the integration of merchant transmission projects and demand-side management programs into the system, to the reconsideration of what is required to attract capacity investments in an ever-evolving *hybrid* market-regulatory regime, PJM itself has spawned many innovations in its pursuit of becoming an effective platform for as competitive a power market as reliability requirements and politics would allow.

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[2] Clifford Winston, "U.S. Industry Adjustment to Economic Deregulation," 12 *Journal of Economic Perspectives,* No. 3, Summer 1998, pp. 89-110.

[3] Paul L. Joskow, "Regulation and Deregulation after 25 Years: Lessons Learned from Research in Industrial Organization," *Review of Industrial Organization (2005)* 26: p. 188.

With that platform now (mostly) in place, on the basis of American experience with regulation, it is a given that industries where market forces subject participants to the competitive struggle spawn more innovation than industries where market forces are absent. As with the airlines and telecommunications businesses, the effect of these innovations takes time to materialize. Over time, however, their effect snowballs and brings permanent enhancements to consumer welfare. We have also learned from these other industries that restructuring of major industries is the work, not of a few years, but of a generation. By that standard, PJM's effects after 10 years of introducing competition to electric markets is still in the early stages.

Appendix I: ESAI POWER FLOW MODELING

To assess the efficiencies of centrally dispatching the PJM RTO system, ESAI utilized a modeling system from PowerWorld Corporation. This model contains all of the modeling algorithms that define the transmission and generation systems and more importantly, that calculate power flows and prices across the system. ESAI inputs all generator information and other system data such as interface constraints and import/export flows. ESAI utilizes proprietary fuel forecasts, generator heat rates, and bid behavior to develop the economic information required for the generator bid curves embedded in the model.

ESAI uses PowerWorld's Security Constrained Optimal Power Flow (SCOPF) tool to achieve an economical operation of the system while considering not only normal operating limits, but also violations that would occur during contingencies. The SCOPF changes the system pre-contingency operating point so that the total operating cost is minimized, and at the same time no security limit is violated if contingencies occur.

The SCOPF has the ability to produce bus locational marginal prices that fully and simultaneously model the economics and the security of the network. This function is indispensable to simulate the performance of a system, region, or utility in a market environment, and to analyze the system conditions that result in high marginal prices. They are also used to study the effects and economic impact of network congestion. The computation of security-constrained locational marginal prices in Simulator follows the philosophy of PJM's market design.

ESAI uses the model in a DC mode, which calculates price differences due to system congestion, but ignores system losses. This is consistent with the PJM operation of the Day Ahead Market models and allows for an equal comparison with results expected from the actual Day Ahead Market.

ESAI uses over 1,100 contingincies in its N-1 security constrained dispatch analysis. This means that the model opens (takes out of service) each of the specified lines and transformers, one at a time, and then redispatches the system on an optimal basis such that no line or transformer capacities are exceeded. The contingencies represented are on the 138 kV systems and higher.

Case Comparison Methodology

Four distinct powerflow cases were developed for this analysis to represent the system on a pre-integration basis and a post-integration basis. Each of the cases below were developed for the system as it exists in 2005 and for the planned system outlook in 2010.

1) Pre-Integration – The PJM Classic area is dispatched centrally while each of the merged areas – AP, ComEd, AEP, DPL, DLCO and Dominion – are each individually dispatched. All dispatches are on least cost economics while maintaining security limits.

2) Post-Integration – The full PJM RTO is dispatched centrally, optimized as a whole for least cost economics while maintaining security limits on the system due to contingencies.

The cases were run at 5,000 MW increments from 20,000 MW to 55,000 MW based upon the PJM Classic load profile – however, all area loads were scaled in tandem with the PJM classic loads. At each load level, the total PJM price (or PJM plus 'non-merged areas' price) was calculated by load-weighting the area or zonal prices to achieve a representative RTO price for that specific load level.

In this manner, ESAI developed a set of load-weighted prices for each load level in each of the four cases that were assessed. The table below shows the comparison of the 2005 case data. The Dispatch Optimization Improvement is the difference in the two cases.

The results are again load weighted against the annual load profile of PJM. We used the load profile for 2004 as the most recent data set. By applying the annual load profile, we can get a load sensitized result which in this case was $0.79/MWh. This is the average savings per megawatt-hour calculated for centrally dispatching the full PJM RTO as opposed to individual regional dispatches.

Table 1

Dispatch Optimization of Expanded PJM RTO Vs PJM Classic: 2005 Case

System Load, MW	PJM Classic*	Expanded PJM RTO	Dispatch Optimization Improvement	% Of Total Load	Load Weighted Contribution To Dispatch Optimization Improvement
20,000	$33.89	$36.90	($3.01)	0.06%	($0.00)
25,000	$39.11	$39.56	($0.46)	12.17%	($0.06)
30,000	$46.09	$44.85	$1.25	24.55%	$0.31
35,000	$50.43	$49.40	$1.03	33.32%	$0.34
40,000	$60.55	$59.31	$1.24	18.40%	$0.23
45,000	$69.55	$70.57	($1.02)	8.76%	($0.09)
50,000	$86.91	$85.77	$1.14	2.45%	$0.03
55,000	$114.42	$103.27	$11.15	0.29%	$0.03
			Total RTO Dispatch Benefit		**$0.79**
		Benefit At 700 TWh Net Energy Consumption			***$554,000,000***

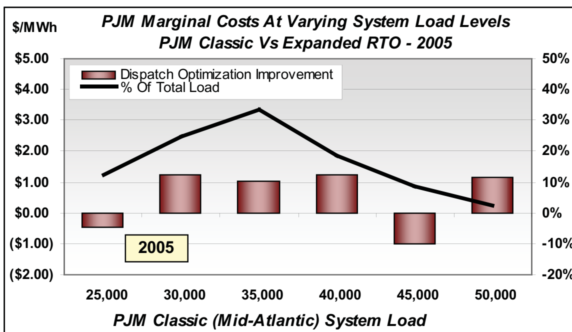
* - Includes disaggregated dispatch of new areas.

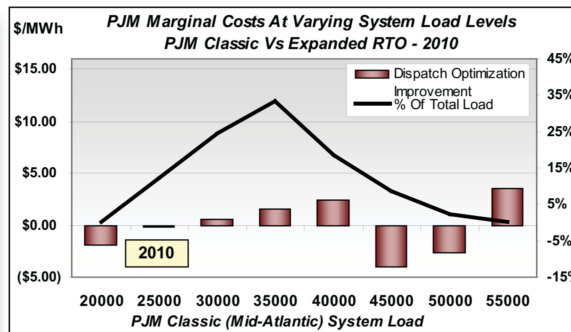
A comparison is shown below of results from the 2010 cases. The overall savings in 2010 are slightly lower on a MWh basis at $0.68/MWh, however, load growth takes the total energy consumption up to 750 TWh and also provides a result of just over $500 million on an annual basis.

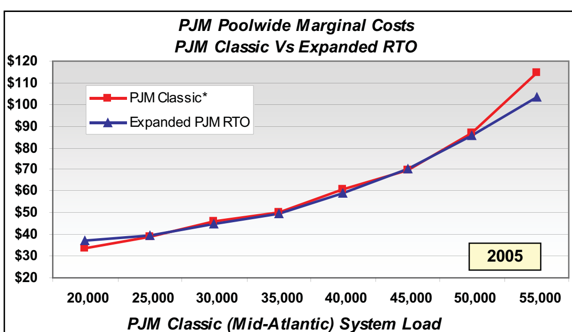
Table 2

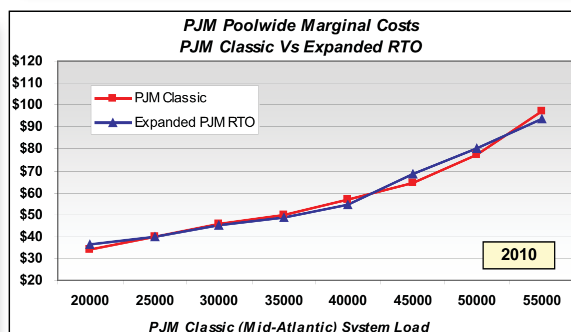
Dispatch Optimization of Expanded PJM RTO Vs PJM Classic: 2010 Case

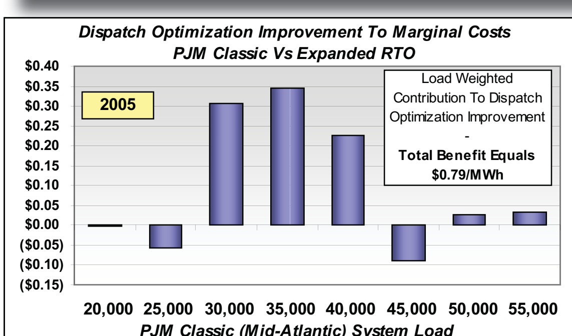
System Load, MW	PJM Classic	Expanded PJM RTO	Dispatch Optimization Improvement	% Of Total Load	Contribution To Dispatch Optimization - Load Weighted
20,000	$34.26	$36.21	($1.95)	0.06%	($0.00)
25,000	$39.70	$39.84	($0.14)	12.17%	($0.02)
30,000	$45.77	$45.21	$0.56	24.55%	$0.14
35,000	$50.01	$48.43	$1.58	33.32%	$0.53
40,000	$56.59	$54.21	$2.38	18.40%	$0.44
45,000	$64.24	$68.26	($4.01)	8.76%	($0.35)
50,000	$77.57	$80.21	($2.63)	2.45%	($0.06)
55,000	$97.33	$93.82	$3.52	0.29%	$0.01
			Total RTO Dispatch Benefit		$0.68
			Benefit At 750 TWh Net Energy Consumption		*$506,000,000*

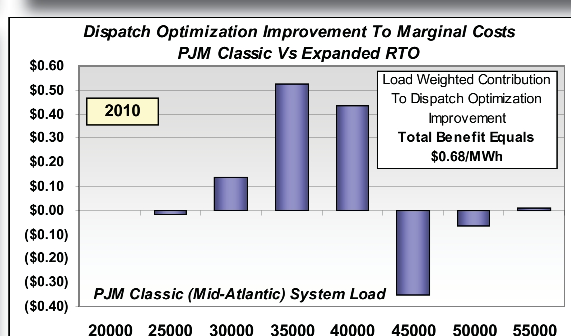












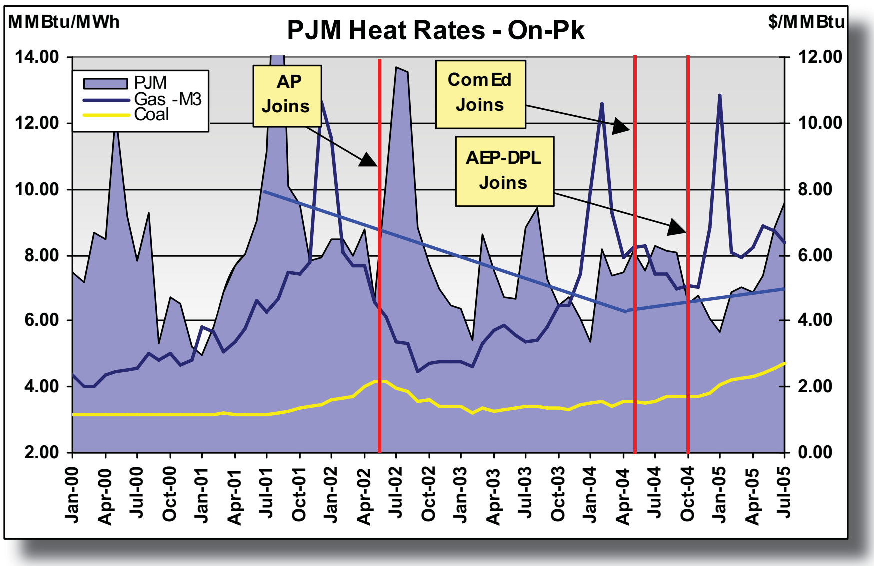
Load Flow Case Results At 45,000 MW System Load (PJM Classic) - Disaggregated Dispatch

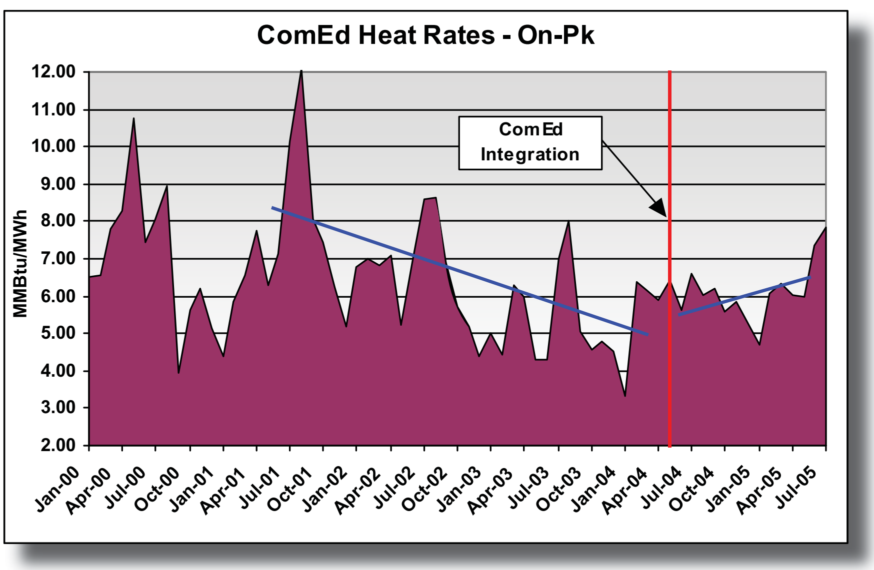
Area #	Area Name	# of Buses	AGC Status	MW Marg. Cost (Ave Weighted by Load)	Gen MW	Load MW
31	PSEG	488	OPF	$100.24	3,361	8,084
145	VAP	532	OPF	$91.12	15,358	14,008
28	JCPL	699	OPF	$89.10	2,269	4,665
37	RECO	14	OPF	$87.11	-	329
34	AE	438	OPF	$85.67	1,262	2,130
30	PECO	412	OPF	$85.03	3,289	6,437
36	UGI	34	OPF	$83.64	47	140
29	PL	346	OPF	$82.87	6,249	5,434
27	METED	244	OPF	$81.89	2,755	2,067
32	BGE	474	OPF	$76.85	1,975	5,426
35	DP&L	478	OPF	$76.84	2,111	3,097
33	PEPCO	195	OPF	$71.60	3,093	5,098
26	PENELEC	462	OPF	$66.00	2,987	2,092
363	NI	1356	OPF	$59.01	18,302	17,537
201	AP	466	OPF	$46.73	5,950	6,582
209	DPL	111	OPF	$44.96	2,820	2,779
205	AEP	1076	OPF	$43.75	20,567	18,643
215	DLCO	93	OPF	$41.32	2,382	2,189
					94,778	106,737

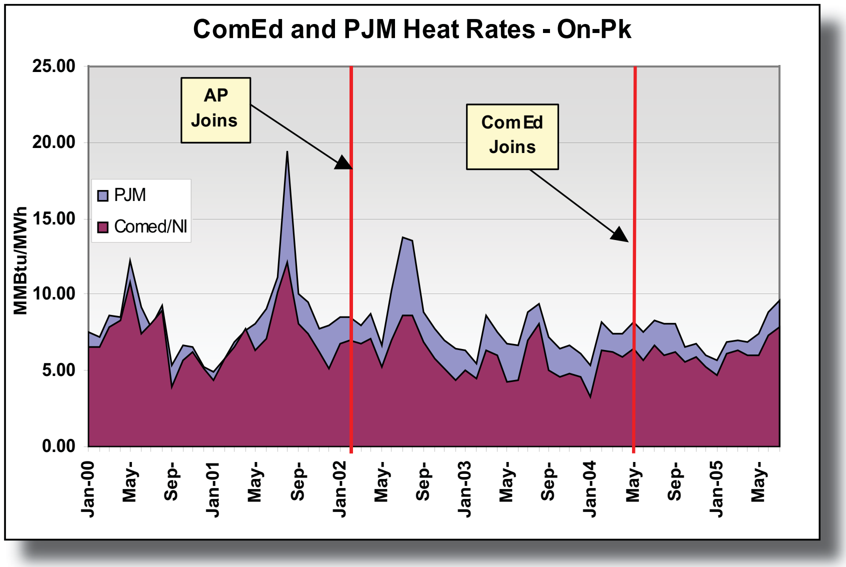
Load Flow Case Results At 45,000 MW System Load (PJM Classic) - Central RTO Dispatch

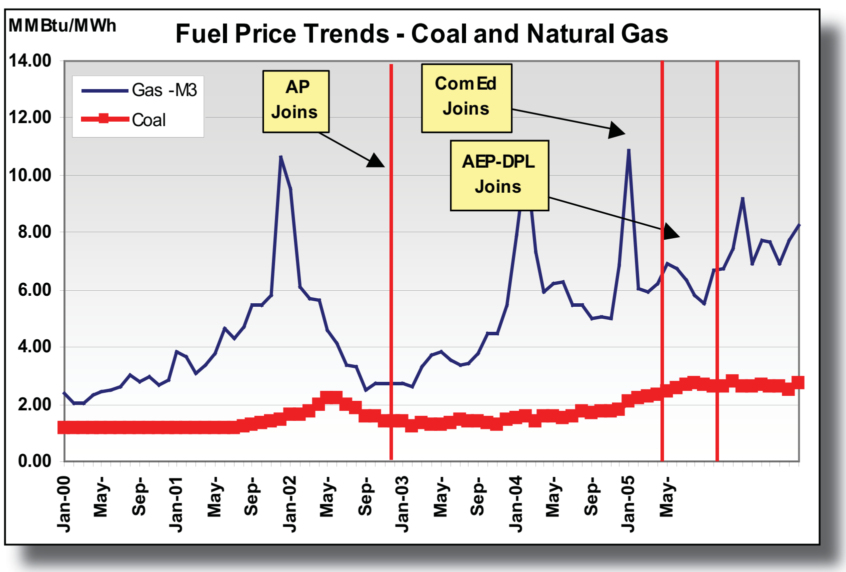
Area Num	Area Name	# of Buses	AGC Status	MW Marg. Cost (Ave Weighted by Load)	Gen MW	Load MW
31	PSEG	488	OPF	$96.70	3,104	8,084
33	PEPCO	195	OPF	$90.26	3,988	5,098
32	BGE	474	OPF	$89.09	2,243	5,426
28	JCPL	699	OPF	$88.82	2,251	4,665
34	AE	438	OPF	$86.50	1,264	2,130
30	PECO	412	OPF	$85.66	3,291	6,438
27	METED	244	OPF	$82.25	2,755	2,067
29	PL	346	OPF	$81.10	5,965	5,434
145	VAP	532	OPF	$80.33	13,205	14,008
36	UGI	34	OPF	$79.07	38	140
35	DP&L	478	OPF	$77.91	2,154	3,097
201	AP	466	OPF	$63.54	6,551	6,583
37	RECO	14	OPF	$62.56	-	329
26	PENELEC	462	OPF	$60.96	2,987	2,092
363	NI	1356	OPF	$51.49	17,940	17,537
205	AEP	1076	OPF	$50.92	20,995	18,643
209	DPL	111	OPF	$50.72	3,305	2,779
215	DLCO	93	OPF	$49.81	2,573	2,189
					94,610	106,740

Appendix II:
Additional Heat Rate Analysis





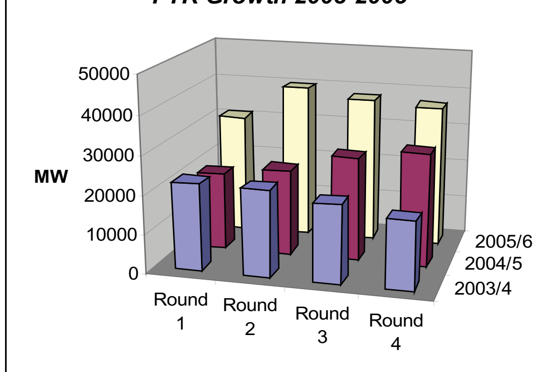

ComEd and PJM Heat Rates - On-Pk
MMBtu/MWh
25.00
20.00
15.00
10.00
5.00
0.00
AP Joins
ComEd Joins
PJM
Comed/NI
Jan-00
May-
Sep-
Jan-01
May-
Sep-
Jan-02
May-
Sep-
Jan-03
May-
Sep-
Jan-04
May-
Sep-
Jan-05
May-


MMBtu/MWh
Fuel Price Trends - Coal and Natural Gas
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Gas -M3
Coal
AP Joins
ComEd Joins
AEP-DPL Joins
Jan-00
May-
Sep-
Jan-01
May-
Sep-
Jan-02
May-
Sep-
Jan-03
May-
Sep-
Jan-04
May-
Sep-
Jan-05
May-

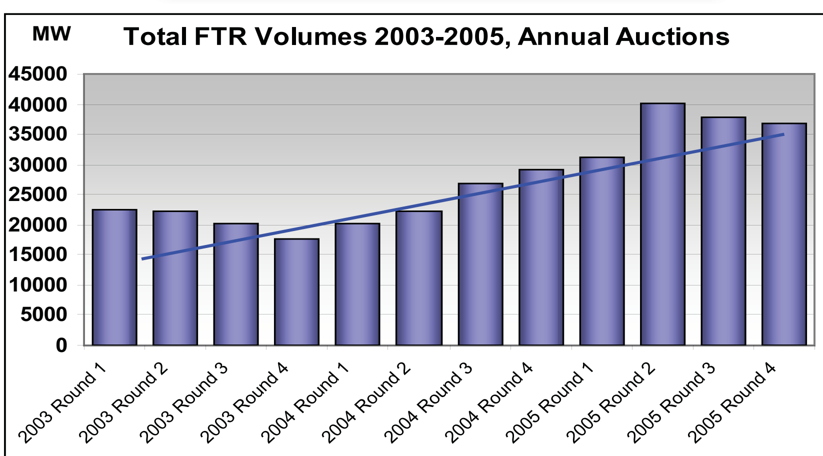
Appendix III: Additional FTR Analysis

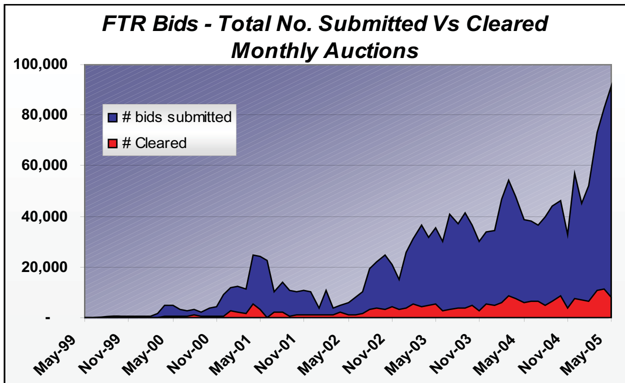
Annual FTR Auction Results												
	2005-6				**2004-5**				**2003-4**			
MW Cleared	Round 1	Round 2	Round 3	Round 4	Round 1	Round 2	Round 3	Round 4	Round 1	Round 2	Round 3	Round 4
All	***31,073***	***40,017***	***37,852***	***36,778***	***20,173***	***22,294***	***26,925***	***29,160***	***22,565***	***22,255***	***20,077***	***17,605***
Obligation	23868	30593	26053	24713	18373	17921	20010	19317	16418	17087	12794	11864
Option	7205	9424	11799	12065	1800	4373	6915	9843	6147	5168	7283	5741
On-Peak												
Obligation	6616	10201	8217	12989	8185	7378	7579	7805	5056	6195	3411	3212
Option	2555	4713	5193	5266	1124	2227	3581	5479	1889	2313	4054	2675
Off Peak												
Obligation	6127	7233	5530	5582	5350	5110	6004	6319	4976	4812	3605	3164
Option	1489	4606	5792	6736	532	1866	3079	4365	2064	1955	3130	2800
24 Hr												
Obligation	11125	13159	12149	11408	4838	5432	6428	5192	6386	6080	5778	5489
Option	3161	105	800	63	143	280	255	0	2194	900	100	265

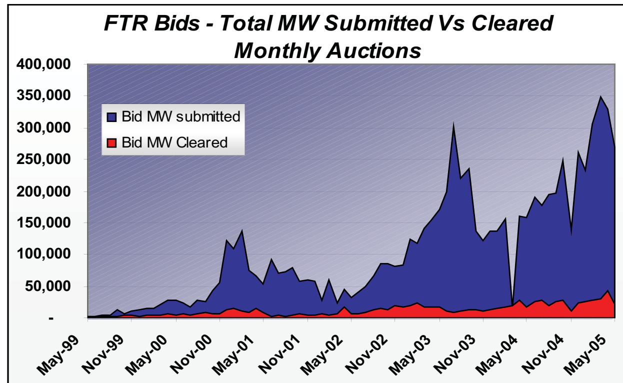
FTR Growth 2003-2005

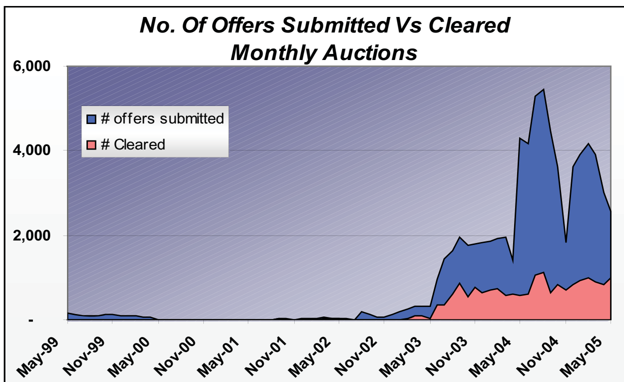


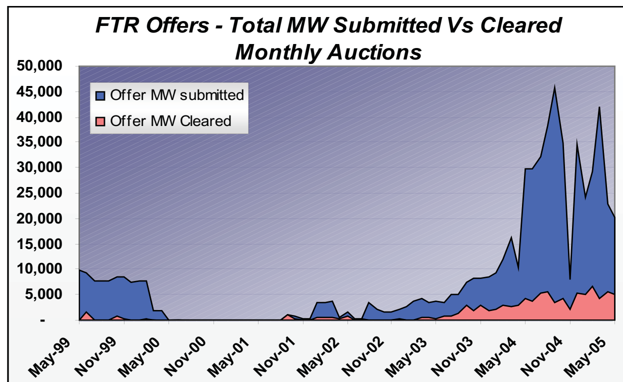
Total FTR Volumes 2003-2005, Annual Auctions

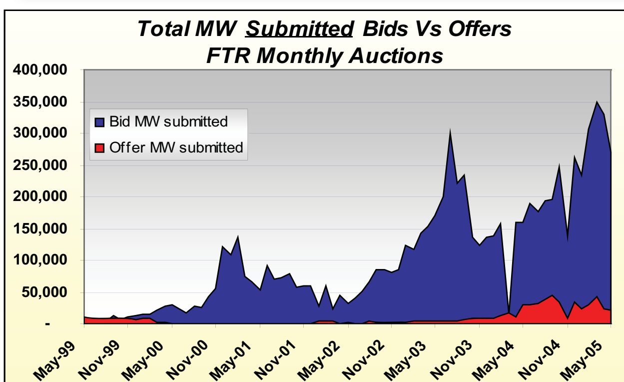


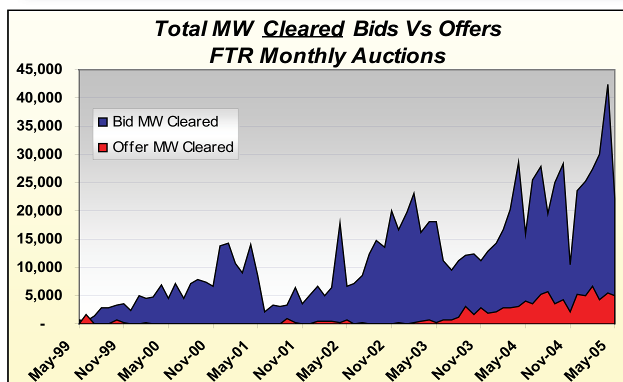

FTR Bids - Total No. Submitted Vs Cleared
Monthly Auctions
bids submitted
Cleared

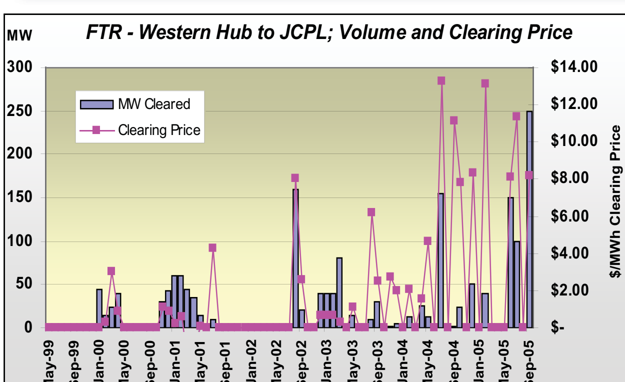

FTR Bids - Total MW Submitted Vs Cleared
Monthly Auctions
Bid MW submitted
Bid MW Cleared

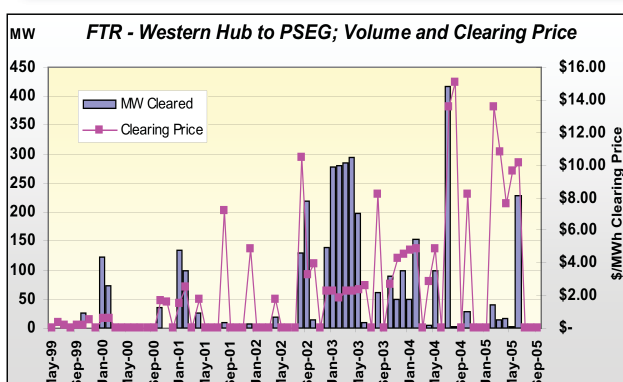

No. Of Offers Submitted Vs Cleared
Monthly Auctions
offers submitted
Cleared

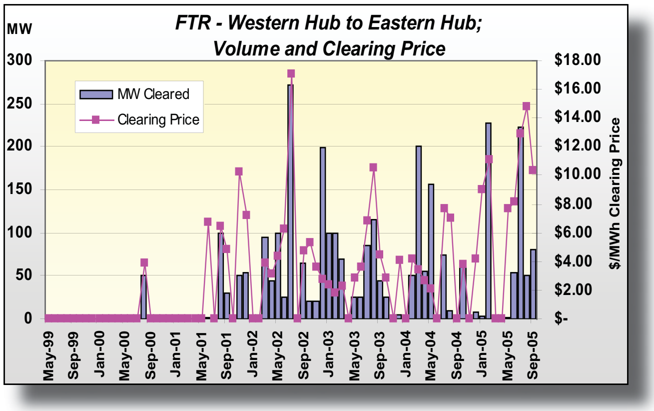

FTR Offers - Total MW Submitted Vs Cleared
Monthly Auctions
Offer MW submitted
Offer MW Cleared

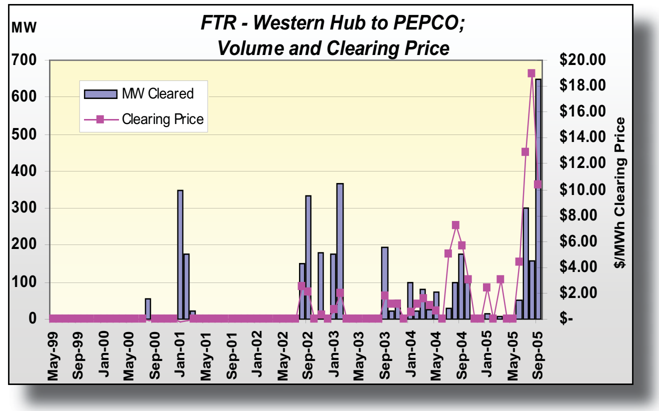

Total MW Submitted Bids Vs Offers
FTR Monthly Auctions
Bid MW submitted
Offer MW submitted

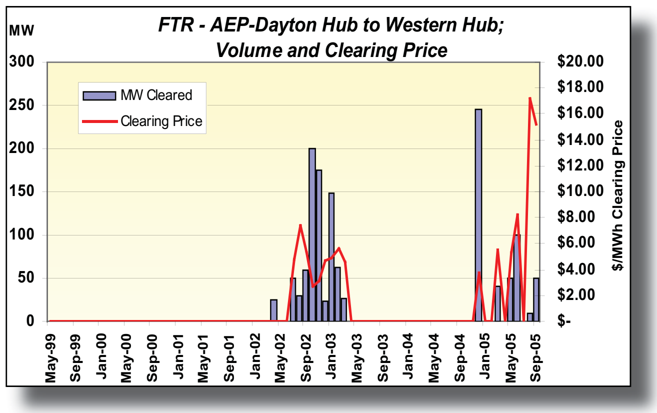

Total MW Cleared Bids Vs Offers
FTR Monthly Auctions
Bid MW Cleared
Offer MW Cleared


MW
FTR - Western Hub to JCPL; Volume and Clearing Price
MW Cleared
Clearing Price
$/MWh Clearing Price


MW
FTR - Western Hub to PSEG; Volume and Clearing Price
MW Cleared
Clearing Price
$/MWh Clearing Price


FTR - Western Hub to Eastern Hub;
Volume and Clearing Price
MW
MW Cleared
Clearing Price
$/MWh Clearing Price


FTR - Western Hub to PEPCO;
Volume and Clearing Price
MW
MW Cleared
Clearing Price
$/MWh Clearing Price


FTR - AEP-Dayton Hub to Western Hub;
Volume and Clearing Price
MW
MW Cleared
Clearing Price
$/MWh Clearing Price