2005 Performance Review of Electric Power Markets
Update and Perspective

Review Conducted for the Virginia State Corporation Commission*

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Executive Summary

Retail Market Overview

Currently, most states have decided to either postpone their efforts to implement retail access or have stopped considering adopting it altogether. Sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Two states allow retail access for larger customers only; Nevada, which modified its original law to limit access to just larger customers and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation, Arkansas and New Mexico have repealed their laws, California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana has also been dealing with the severe aftermath of the western power crisis, and extended the transition period to retail access for smaller customers. Montana implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 has been postponed to 2027.

Twenty six states are no longer considering restructuring at this time. None of these states appear to be working in any meaningful way toward passage at this time. No state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. The states that did not pass legislation, but were in the process of considering it, either gradually lessened their efforts to allow time to consider what was occurring in the West or they abruptly stopped any activity that was ongoing at the time. Thus, a total of 34 states have repealed, delayed, suspended, limited retail access to just large customers, or are now no longer considering retail access.

Only two states have residential load “switching” greater than 10 percent in 2005. One state is Ohio where most of the residential switching in the state has been through the state's aggregation program. The other is Texas that is now the most active state in the country in terms of residential customers choosing a supplier. Most states are well below five percent. Nine states are at or near zero percent.

The percentage of commercial and industrial load served by competitive suppliers in early 2005 was considerably higher than for residential load. Six states, D.C., Illinois, Massachusetts, Maine, New York, and Texas, had a larger customer group (either commercial, industrial, or combined commercial and industrial) with greater than 50 percent of load served by competitive suppliers. Two were above 80 percent. Four states had no larger customer category above ten percent.

In terms of total state load served by competitive suppliers, five states had greater than 30 percent of the total state load being served by competitive suppliers, D.C., Illinois, Maine, New York, and Texas. However, six states had less than ten percent of the total state load being served by competitive suppliers.

Evaluation of the Wholesale Market Results to Date

Most observers of electric industry restructuring would agree that it has been more difficult and more complex than believed when the process began in the 1990s. Because of the technical nature of electric supply and the many functions that remain regulated, the task was likely to be difficult. Difficulty and complexity are not problems in themselves, but may lead to unintended consequences that designers could not have anticipated. The current Regional Transmission Organization (RTO) structure that has emerged was not created through a specific design plan. Instead, it evolved through a series of Federal Energy Regulatory Commission (FERC) orders, responses by the RTOs themselves, and the clash of interest groups in the FERC proceedings. Of course, the industry structure prior to the start of restructuring was also very influential, that is, the generation, distribution, and transmission infrastructure that was built over decades and the industry-specific events that preceded restructuring.

Just how competitive a particular industry is depends on three general structural characteristics: (1) the market concentration or market share of the suppliers in the industry, (2) the ease with which alternative suppliers can enter a market, and (3) the overall market demand characteristics of the product. By examining these three characteristics together, the degree of competitiveness of any industry or market can be determined. In the wholesale electric supply industry, all three characteristics clearly play an important role. Markets are very concentrated for most geographic regions of the country, even for multi-state wholesale regions. Market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. Mass storage of electricity for later use during peak hours is generally impractical for many regions of the country. Also, demand for electricity is very inelastic, particularly in the short-run (less than one year) since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers.

The possibility of coordinated interaction and tacit collusion could have particular relevance for electricity markets, given the nearly continuous interaction that firms have in RTO and ISO markets. A merger of firms of any size within the same RTO means fewer firms in the market and makes coordination more possible. In its analysis of the Exelon/PSEG merger, FERC did not examine the possibility of collusion. Also, the ISO and RTO market monitors do not examine this possibility either.

Strategic bidding and withholding are clearly issues that need to be examined. There are academic papers that suggest that strategic bidding could happen and how it could (and perhaps actually does) happen in LMP markets. While academics have been studying this issue for a few years, it is not purely an academic exercise. The 2000-2001 western power crisis period demonstrated that it can happen. However, outside of the analysis on that crisis, no analysis has been done that studies actual bidding behavior in other ISO or RTO markets. However, the academic discussion and what bidders could or may be able to do in these markets, suggests that, at the very least, the issue of strategic bidding needs to be studied. As another academic paper warns, "[g]iven the cost of mistakes, e.g., the California electricity market in 2000, a more than incremental change in a market design requires careful analysis, especially of how the participants can outwit the designers."

All these characteristics and features taken together suggest that the market structure that is emerging is certainly not perfectly competitive, an impossible standard for any market to reach, nor could the structure be characterized as a pure monopoly, that is, one supplier – although that may occur in some local areas or subregions of an RTO or ISO under certain circumstances. Rather, the structure that is suggested is one of an oligopoly, defined as a market where there are a few firms supplying all or most of the output.

Recent Events

Two significant recent events have occurred that will likely have a material impact on the development of wholesale markets across the country. First, the Federal Energy Regulatory Commission (FERC) approved the Exelon merger with PSEG, without a hearing and second was the passage of the Energy Policy Act of 2005, which included the repeal of the Public Utility Holding Company Act of 1935 (PUHCA). The repeal of PUHCA and its impact on FERC's merger reviews will depend on FERC's implementation of the new legislation. However, most industry observers seem to agree that this will almost certainly lead to more and larger mergers, and more combination energy companies (of electric supply and distribution, natural gas, oil, etc). Together these events suggests that it is likely that there will be even greater concentration of the industry, and in particular, increased concentration of ownership of generation resources. If the result is an increase in the concentration of generation ownership, then, as economic theory suggests, the result will be less competitive wholesale electricity markets.

It is not known with any degree of certainty if there is significant market power in PJM or other ISO and RTO markets. The analysis conducted so far of the ISOs and RTOs themselves is insufficiently detailed enough to warrant a conclusion one way or the other. The conditions are such that it is possible that considerable amount of market power could be exercised. Only an independent analysis will help shed some light on the issue.

An independent analysis of the wholesale market and its potential impact needs to be conducted in a comprehensive and rigorous manner. This is needed to characterize the condition of regional wholesale markets and determine the likely outcome of the regional markets on retail prices. This study needs to be a structural analysis to determine whether there is in fact a sufficient level of competition among suppliers or, as discussed, they are operating closer to an oligopoly structure with tacit collusion.

This type of analysis is impossible without access to detailed price and bidding data. Unfortunately, data restrictions limit access to external analysis. Either states or FERC or other federal agencies, needs to mandate such a study to allow the required data access. This analysis needs to be independent of the ISOs and RTOs so that it is not influenced by any single or group of market participants that obviously would have an interest in the outcome of the analysis. Until this is done, we are “flying blind” and operating on the assumption that we have sufficient altitude and that there are no mountain ranges in front of us.

State transition periods have been ending and many of these states are seeing significant price increases. In these cases, retail customers are seeing the impact that higher fuel prices are having on wholesale electricity prices. However, while fuel costs have increased across the country, not all states have seen the same impact from these increases on their retail electric prices. According to EIA figures, the national average retail price for all sectors from 2004 through April 2005 increased by 3.6 percent. This suggests that, nationally, the full impact of fuel cost increases are not affecting retail rates at the same pace.

In the case of retail customers in restructured states where the transition period has ended and their price is now determined in the wholesale market, the customers are now taking the brunt of the impact that increased fuel prices are having on wholesale prices. It appears that, from the data so far, most retail customers (especially residential) in restructured states where the transition period has ended and the price is now based on the wholesale market, are seeing prices increase faster than in the non-restructured states or states still in transition with a price cap. At best, at this point in time, no discernable overall benefit to retail consumers can be seen from restructuring.

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Part A

Results and Update of Electric Power Industry Restructuring Activities

Introduction

This is the fifth year that a section of the SCC's report to the Virginia General Assembly and the Governor has been done on the development and performance of wholesale and retail electric power markets around the country, as required under the Virginia Electric Utility Restructuring Act. Last year's report was comprehensive in that it covered the developments in all regions of the country. Past reports have all provided detailed descriptions of the development of the regional wholesale markets and state retail markets. This included the formation and growth of the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), descriptions of the markets they operate, and analysis of the performance of these regional wholesale markets. Also included in past reports was the development of state retail markets, such as shopping status, offers to residential customers, and details on state legislation and regulatory commission implementation.

This year's report provides an overview and update of previous performance review reports on the wholesale and retail market developments and a perspective on what has been learned so far. The report is divided into two parts. Part A covers the results so far from industry restructuring and provides updates of wholesale prices and retail market developments, including retail prices that are now beginning to show the impact from restructuring. Part B provides a perspective on the developing industry structure so far and how it relates to the legislative and regulatory goal of fostering the development of competitive wholesale and retail markets.

Goals of Restructuring and Results to Date

Among the principal reasons for the movement away from the traditional cost-based regulation and toward generation competition and retail access was the belief that competition would provide better incentives to control costs and that these cost savings would be passed on to consumers–resulting in lower prices for all customer classes. Other reasons for favoring a move away from cost-based regulation included increased use of innovative technologies in generation and the belief that it would give customers more options in terms of price, fuel source, and service.

In the mid-1990s, it was common for advocates for competition to list the advantages, as they saw it, in moving from regulated monopolies to competitive markets. In testimony before Congress, a spokesperson for the Electric Power Supply Association[1] noted:

> Competition . . . can be expected to:
> - Provide the lowest prices possible.
> - Allow all customers, for the first time ever, to choose their provider of electricity.
> - Improve technology and services.
> - Enhance reliability.
> - Improve environmental performance.
> - Protect consumers from anti-competitive behavior and market power abuses.
> - Strengthen the competitiveness of American industry.

In 1996, states began to pass restructuring legislation and FERC issued its Order 888, which required transmission open access. Nearly a decade has passed since these events occurred and seven years since several states began to open their retail markets in 1998. Attempts are now being made to assess how well these efforts have progressed toward moving to competitive electricity markets. Given the variety of views on the subject, it is not too surprising that the assessments vary from showing no benefit to significant savings to consumers from restructuring. While it will take time to see to what extent the benefits in the above list are realized, if at all, the focus here will be on the first item, retail prices.

[1]Written statement of Steven D. Burton, speaking before the House Judiciary Committee Oversight Hearing on Anti-trust Aspects of Electricity Deregulation, June 4, 1997. Steven D. Burton was Senior Vice President and General Counsel for Sithe Energies, Inc. and Chair, Electric Power Supply Association (EPSA).

A recent study claims that consumers have benefitted $15.1 billion from wholesale competition in the Eastern Interconnection from 1999 through 2003.[2] The study compares a "with wholesale competition" case to a "without wholesale competition" case to estimate the benefit from competition. The benefits, according to the study, come from two sources, fuel and variable O&M cost savings (almost $6.4 billion for the five year period; this is the fuel and variable O&M cost difference between the two cases) and costs that are said to be avoided but that would have been incurred if the power had been supplied under cost-of-service regulation.

There are, however, at least three serious limitations to the analysis. First, the study assumed that there are no competitive energy purchases under the "without wholesale competition." Energy purchases by regulated utilities predate the industry restructuring that began in the 1990 by many years. While there are more energy purchase sales in recent years, it is unrealistic to assume none would occur at all in a regulatory scenario. Secondly, and perhaps more seriously, most of the "savings" are from the lower cost for competitively supplied power, but this cost does not include the loss to competitive suppliers of about $11.1 billion. This "savings" is, at best, a temporary one, since it is reasonable to expect that new suppliers will not enter the market to lose money. If the full cost was added (not just the revenue earned), the savings for the five year period would be about $4 billion. Since this is for five years and for the entire Eastern Interconnection,[3] this is not a substantial sum. For comparison, PJM's billings alone for 2005 are estimated to be about $13 billion. Finally, there may well be fuel and variable O&M cost savings from competition that would not occur under regulation, but there are no guarantees that any of those savings are being passed on to consumers.

In contrast, a recent publication by the American Public Power Association (APPA) stated, "it is time to take stock" of the Federal Energy Regulatory Commission's

[2]Global Energy Decisions, "Putting Competitive Power Markets to the Test, The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies," July 2005. A copy of the report was obtained from http://www.globalenergy.com/competitivepower/ .

[3]This includes the entire U.S. east of the Rocky Mountains, except Texas.

(FERC) restructuring policies and make “substantial ‘mid-course corrections.’”[4] The APPA recommends that FERC “reorient its policies to make sure electric consumers in fact—not just in economic theory—benefit from electric restructuring.” The APPA paper focuses on FERC’s Regional Transmission Organization (RTO) policies. It notes that concerns stem from

> APPA members in RTO regions report substantial, across-the-board problems with spiraling RTO costs, unaccountable RTO governance, and ever-increasing provision of RTO services through questionable market mechanisms. These APPA members are unable to obtain or even retain long-term firm transmission service at just and reasonable rates. This is impairing their ability to enter into the long-term generation resource arrangements they need to provide reliable and affordable electric service to their end-use customers.

The costs of RTO and ISO operations have been escalating steadily in recent years. An analysis that collected and compared the annual operating costs of the six RTOs and ISOs currently in operation found that these costs totaled over $1 billion in 2004 (in 2003 dollars).[5] Total annual operating costs have more than doubled since 2000. All the RTOs and ISOs have seen steady cost increases, except the California ISO that decreased in its 2004 annual operating cost from 2003. PJM and the Midwest ISO both exceeded $200 million annual operating costs in 2004 (again, in 2003 dollars). The California ISO had the highest operating cost in 2004 of the six organizations. Obviously, for the period reported, 1997 to 2004, the RTOs and ISOs have greatly expanded their operations in terms of both geographic size and the scope of their operations. Also, in terms of costs per MWh, these costs are relatively modest. For example, the PJM annual cost is about 60 cents/MWh in 2004 – however, this has also doubled since 2000. The average annual growth rate of the total annual operating costs, using these figures from 1998 through 2004, is nearly 29 percent, and these

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[4]American Public Power Association, “Restructuring at the Crossroads: FERC Electric Policy Reconsidered,” December 2004, p. iii.

[5]Margot Lutzenhiser, “Comparative Analysis of RTO/ISO Operating Costs,” August 17, 2004, presentation, Public Power Council.

costs increased over 350 percent overall during this period. If such costs continue to escalate at that rate, RTO and ISO operating costs will become an even more significant policy concern.

While it is important to track industry costs, the bottom line for consumers is what they pay for power and whether there is any discernable benefit from restructuring that can be seen so far. A paper that examined industrial electricity prices,[6] found no benefit to industrial customers from electric industry restructuring. This analysis used EIA data from 1990 through 2003 and concludes that "there is no correlation between restructuring or regulation and improvement in the annual rate of price change" and that "[r]estructuring in the electricity industry has not led to lower industrial prices, nor to decreased rates of annual price increases."[7]

Comparing state industrial consumer prices, the author found that the annual percentage change in industrial prices from one month after the end of the phase-in period through 2003 for all restructured states increased by 0.5 percent. If Maine is removed from the group, the annual percentage increases to 1.7 percent annual percent change.[8] By comparison, prices in regulated states in the continental U.S. for the period 2001 through 2003 increased by 0.3 percent. Regionally, prices in the three areas examined all increased by about two percent annually, 1.8 percent for western restructured states (Arizona, California, Montana, and Oregon), 2.1 percent for Ohio Valley restructured states (Illinois, Ohio, Pennsylvania), and 2.0 percent for New England (New England states without Maine plus New York). Western regulated states' prices increased by 1.0 percent, upper Midwest regulated states' prices increased by 1.3 percent annually, lower Midwest regulated states' prices *decreased* by 1.8 percent

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[6]Jay Apt, "Competition Has Not Lowered US Industrial Electricity Prices," Carnegie Mellon Electricity Industry Center, Working Paper CEIC-05-01, 2005. The paper is available at, www.cmu.edu/electricity.

[7]Apt, p. 8.

[8]Page 6 of the Apt study notes that Maine is dependent on natural gas-fired electric generation, and that "[p]rices in that state began to rise in 2000, but have fallen significantly since . . . completion of two natural gas pipelines from the Sable Island field off Nova Scotia." As summarized later in this report in the state summaries, Maine's retail prices for 2005 have begun to increase significantly.

annually, Ohio Valley regulated states' prices increased 2.5 percent, prices in regulated Vermont *decreased* by 0.8 percent, and southern regulated states (Louisiana and Arkansas through Florida and up to North Carolina) also had *decreased* prices of 0.8 percent annually.

The author summarizes a number of factors that may increase costs and prevent the benefits of competition from reaching consumers.[9] These include noncompetitive markets, wholesale market clearing prices that are paid to all generators, RTO/ISO operational costs, and the increased cost-of-capital that competitive suppliers face.

More recent state price data suggest that prices in restructured states may still be increasing faster than states that did not restructure. A small survey of industrial rates included 15 restructured state utilities and nine non-restructured state utilities.[10] Overall, industrial rates in the sample increased by 5.2 percent from 2004 to 2005. Four states had double digit increases – all in restructured states – Maryland (BG&E with a 33 percent increase), New York (Con Edison with a 15 percent increase), and two companies in Texas (Reliant Energy with a 13 percent increase and Texas Utilities with a 12 percent increase). Eleven states had utilities above the survey average increase, six were restructured states (including the top four listed above) and five were non-restructured states. Eight states had decreases in the price, five of these were less than one percent. However, the largest decrease was in a restructured state – New Jersey utility Public Service Electric & Gas with a 3.5 percent decrease, but that state started with the fifth highest rate in the survey.

[9]These factors are discussed in more detail in, Lester B. Lave, Jay Apt, and Seth Blumsack, "Rethinking Electricity Deregulation", *The Electricity Journal*, 17:8 (2004) at 11-26.

[10]The survey sampled 24 large investor-owned utilities' pricing for industrial customers based on a monthly usage of 450,000 kWh, monthly demand of 1,000 kW, operating power factor of 85 percent and customer-owned transformer equipment. The survey results were obtained from NUS Consulting Group, http://www.nusconsulting.com/ , April 2005.

Regional Wholesale Market Update

Mid-Atlantic/PJM

Figure 1 shows average daily prices for peak hours (day-ahead and real-time markets) for PJM, as well as the AEP Dayton Hub and the ComEd Zone, which was added to PJM in 2004. There is a slow but steady convergence of prices between PJM and ComEd in the five quarter period shown in the graph. Table 1 shows the maximum, average, and minimum peak hour prices in the day-ahead and real-time markets. Prices in ComEd started well below PJM, but by late 2004, prices were much more comparable. This convergence is demonstrated more clearly in Figure 2 on the next page.

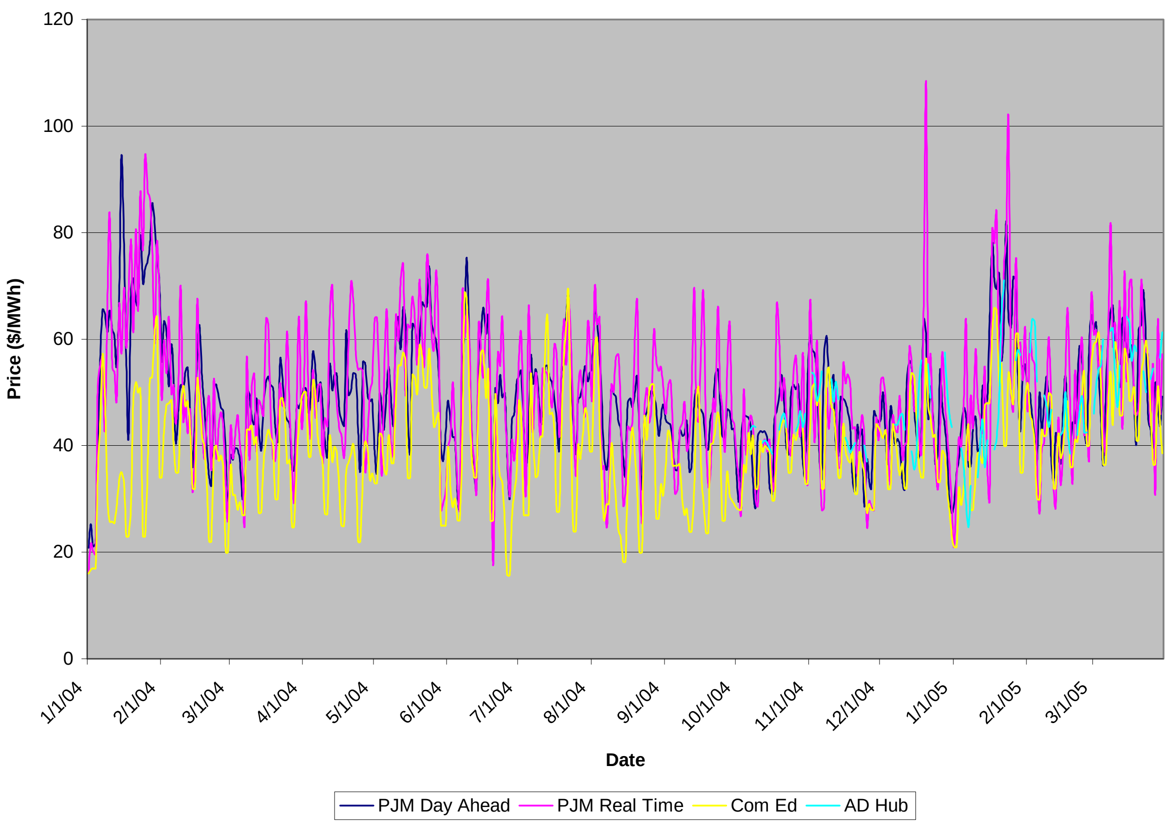


Figure 1. Daily average peak hour prices for PJM regions – PJM (day-ahead and real-time), ComEd region, and AEP Dayton Hub.
Source: PJM for PJM day-ahead and real-time, *Platts Megawatt Daily* for ComEd, and ICE for AD Hub.

Table 1. Peak hour prices in the PJM day-ahead and real-time markets.

Hour	700	800	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000	2100	2200
Max	115	99	93	92	90	86	82	87	90	93	95	129	126	110	103	91
Min	1	7	16	19	20	20	19	18	17	17	21	28	27	25	25	21
Avg	41	45	46	48	50	49	47	47	45	45	48	56	59	56	55	48

Data Source: PJM.

The steady convergence between PJM prices and ComEd prices can be seen more clearly in Figure 2. With distinct prices in February 2004, prices steadily converged over the period. The graph plots the difference between the PJM day-ahead price and the ComEd price and a simple regression line is drawn to show the trend line that demonstrates the convergence. While the prices differed by $10 or more at times, the downward slope of the line shows that there was some convergence. Usually the difference was positive, meaning the PJM price was greater that the ComEd price. A similar trend can be drawn between PJM real-time prices and ComEd prices.

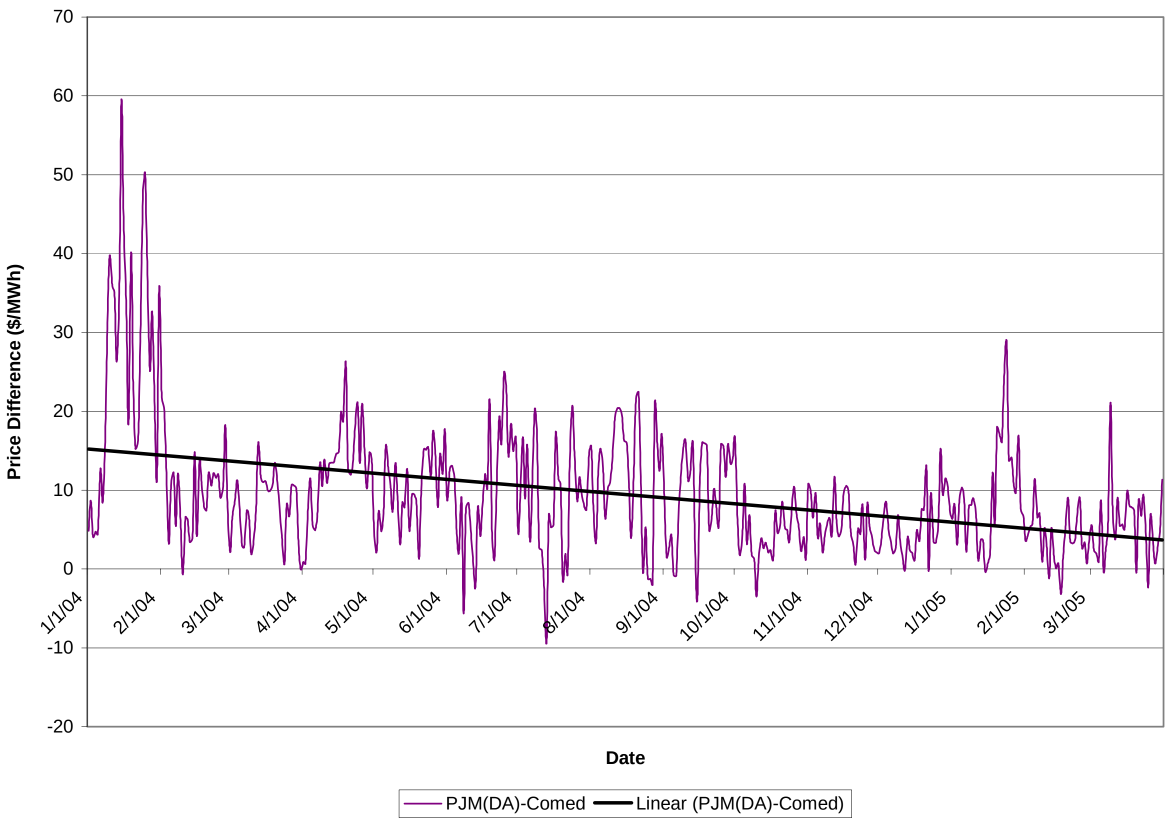


Figure 2. Difference between PJM day-ahead prices and ComEd prices.
Source: PJM for PJM day-ahead and Platts *Megawatt Daily* for ComEd.

Figure 3 shows the price duration curve for PJM, ComEd, and the AEP Dayton Hub. The price duration curve shows the range of prices in each region and what percent of the prices fell above or below a given level (the vertical axis is labeled in decimal form, so, for example, 0.1 is 10 percent and so on). The median price for PJM day-ahead was $64 versus $79 in real-time. These are both higher than AEP Dayton ($39) and ComEd ($46). The middle 50 percent of prices (25 percent of the prices below the median, and 25 percent above the median) for PJM day-ahead were between $55 to $72, while in the real-time market, they were $64 to $96. Prices for ComEd and AEP Dayton were much more stable.

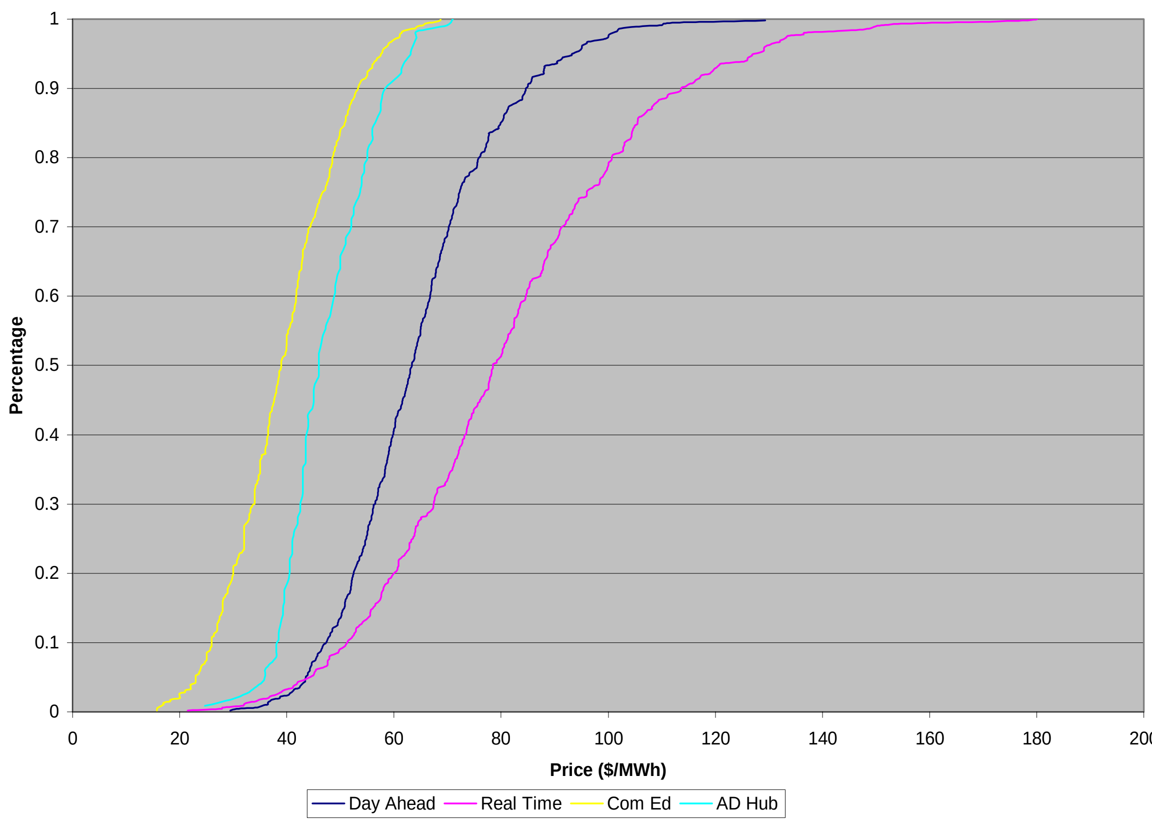


Figure 3. Price duration curve for the daily average peak hour prices for PJM regions – PJM (day-ahead and real-time), ComEd Region, and AEP Dayton Hub.
Source: PJM for PJM day-ahead and real-time, Platts *Megawatt Daily* for ComEd, and ICE for AD Hub.

Figure 4 shows the average day-ahead price for peak hours at four PJM hubs – Eastern, Western, West Int, and New Jersey. As the graph shows, prices at each of the hubs generally are correlated with one another. The New Jersey Hub tended to have the highest prices of the four hubs.

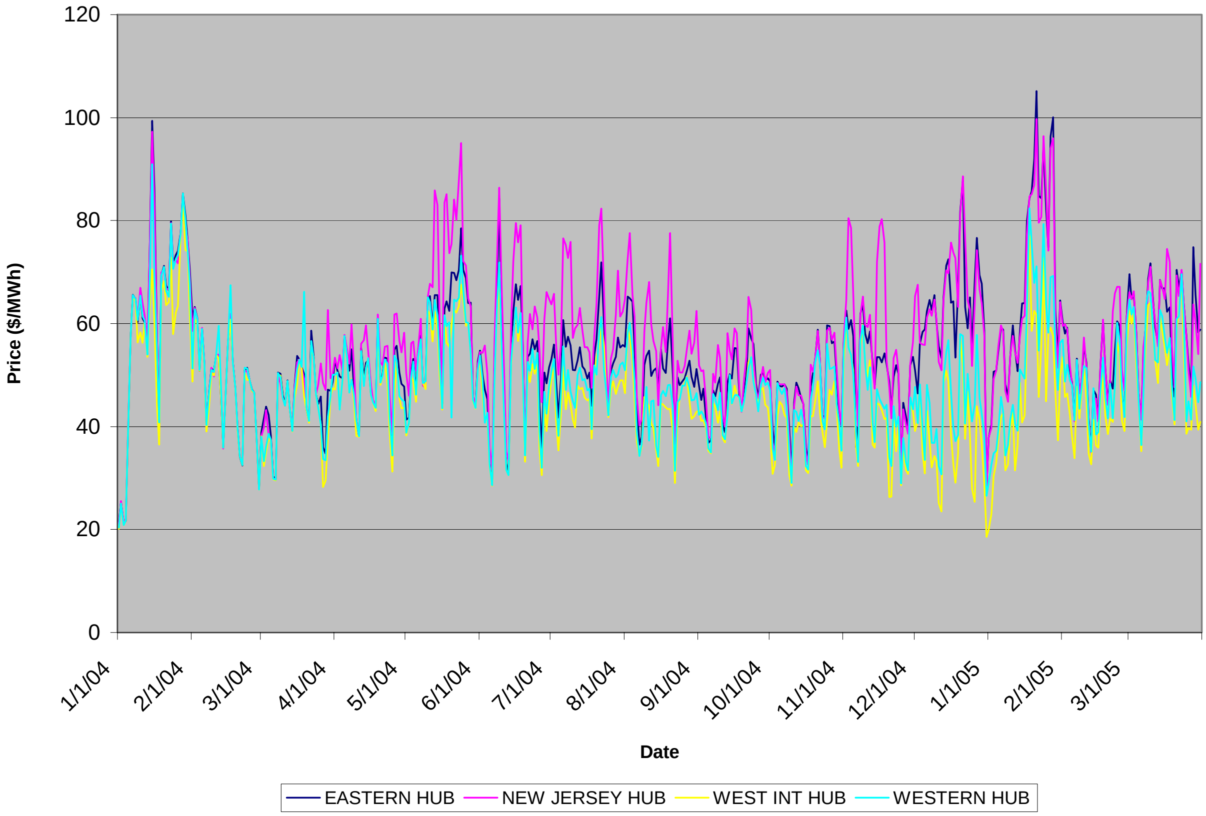


Figure 4. Daily average peak hour day-ahead prices for four PJM hubs. Source: PJM.

Figure 5 shows the price duration curve for four hubs in PJM. The median prices ranged from $36 to $64 (for West Int and New Jersey, respectively). The middle 50 percent of prices for West Int were between $36 to $50, while the middle 50 percent of prices for New Jersey were between $48 to $64. Almost 10 percent of prices at the New Jersey Hub exceeded $75.

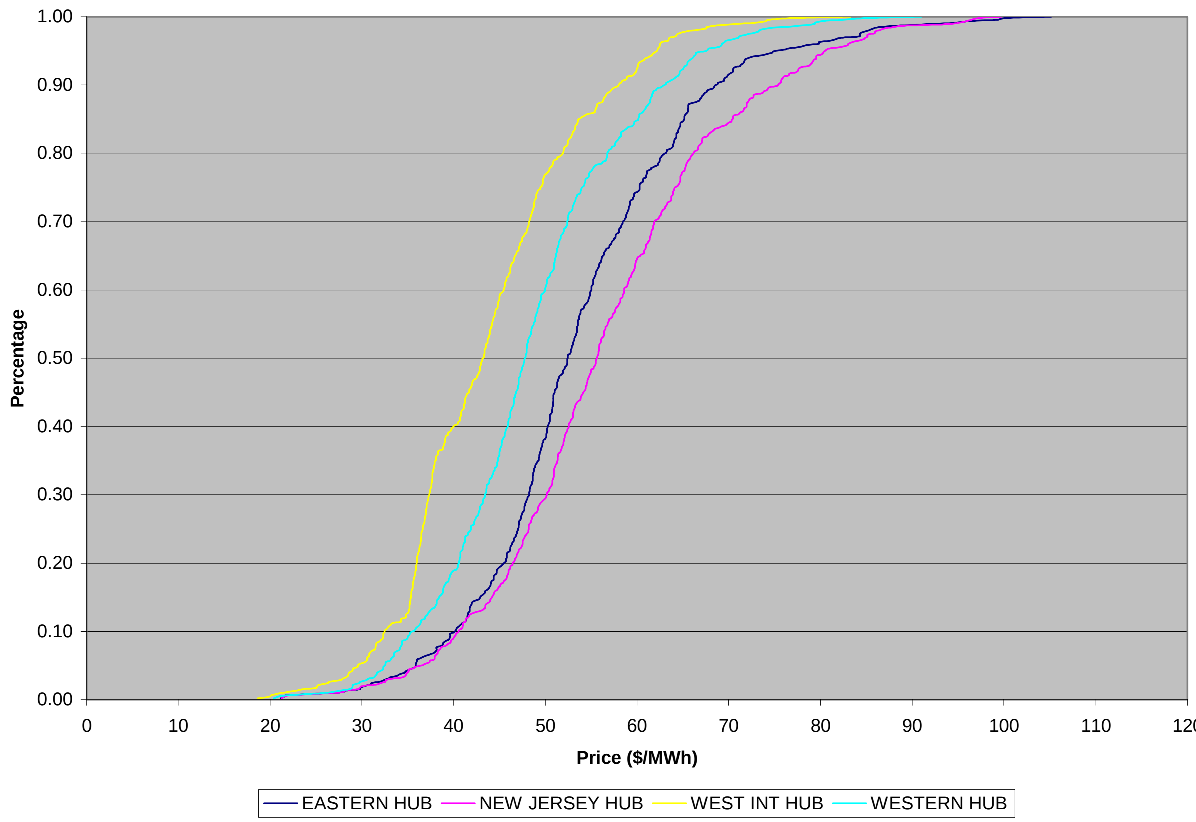


Figure 5. Daily average peak hour prices for four PJM hub day-ahead prices. Source: PJM.

New England

Figure 6 shows the daily prices at the Massachusetts (MA) Hub relative to the monthly average load weighted prices for ISO New England (ISO-NE). The Massachusetts hub experienced a spike in January 2004[11] and January 2005 similar to the spikes experienced in New York. Excluding the month of January for both years, prices tended to be relatively stable in the $50 to $60 range.

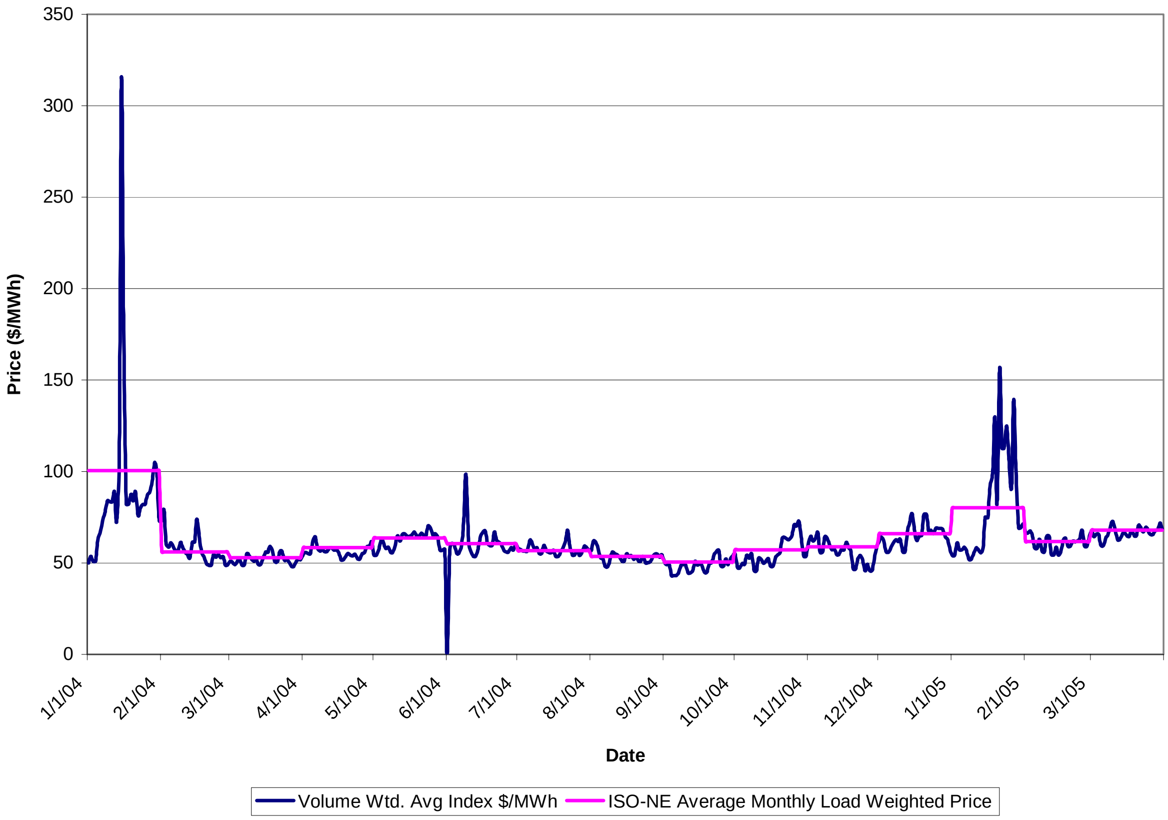


Figure 6. Daily volume weighted price for Massachusetts Hub and the monthly average load weighted price ($/MWh) for peak hours.
Souces: Platt's *Megawatt Daily* for Massachusetts Hub. ISO-NE for ISO-NE average monthly load-weighted prices.

[11]This was during the "Cold Snap" that occurred in the region January 14 through 16, 2004. This was discussed in last year's Performance Review (pp. III-4 to III-7).

Figure 7 shows the volume weighted average monthly prices at the Massachusetts Hub during peak and off peak hour. Prices in peak and off peak hours follow a similar path, though at distinctly different prices. Prices started 2004 at a peak for the entire period. The average monthly price dropped after January. For the duration of the year, price stabilized between $55 and $65 dollars. This lasted until December, where average monthly prices fell below $50, then rose to $80 in January.

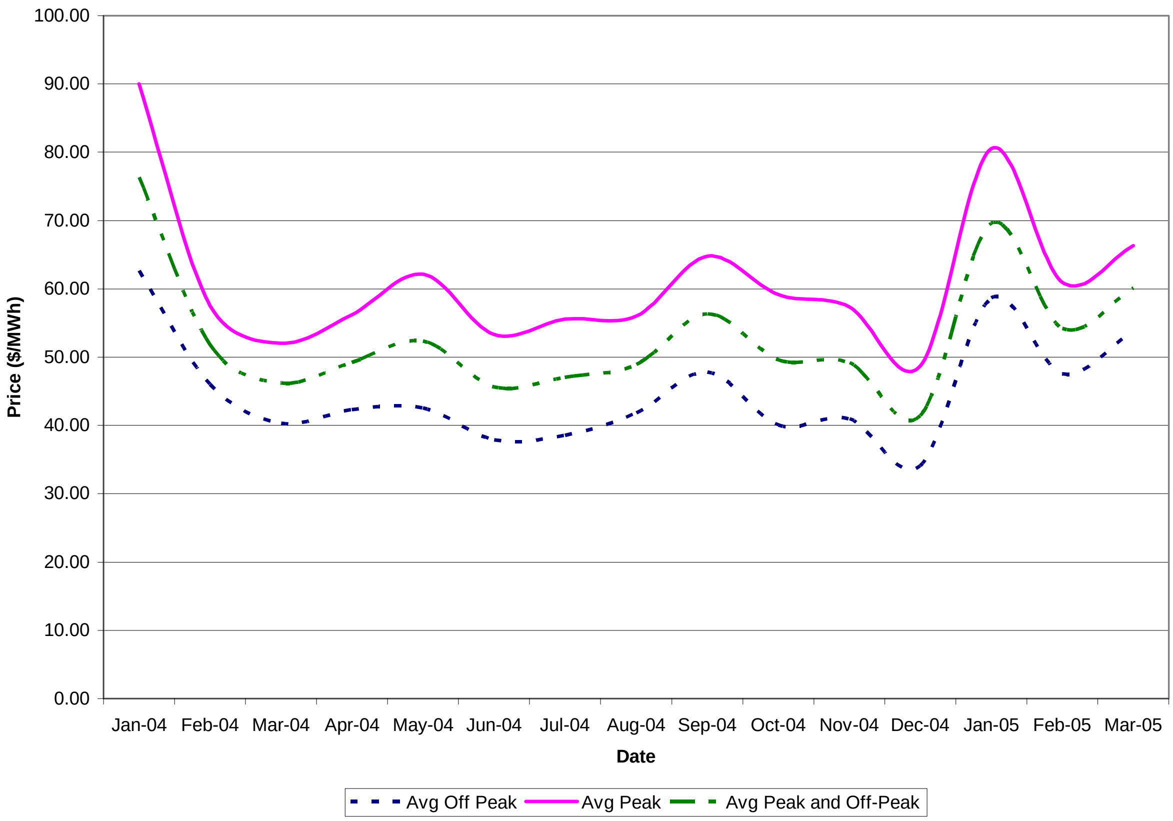


Figure 7. Monthly average volume weighted average prices ($/MWh) for peak hours, off peak hours, and average peak and off peak prices for the Massachusetts Hub. Souces: Platt's *Megawatt Daily*.

The price duration curve for the Massachusetts Hub in Figure 8 shows that prices remained in the $55 to $65 range much of the time. For the time period shown, 50 percent of prices fell between $53 and $65. The Massachusetts Hub showed more dispersion at the high end of prices than the low end. For example, only once did the price fall below $40 ($0 on June 6, 2004). Excluding that day, the range of the lowest 10 percent of prices was $43 to $49, while the highest 10 ranged from $73 to $177 (excluding the $315 that occurred on January 1, 2004). Overall, prices remained fairly stable for the period examined.

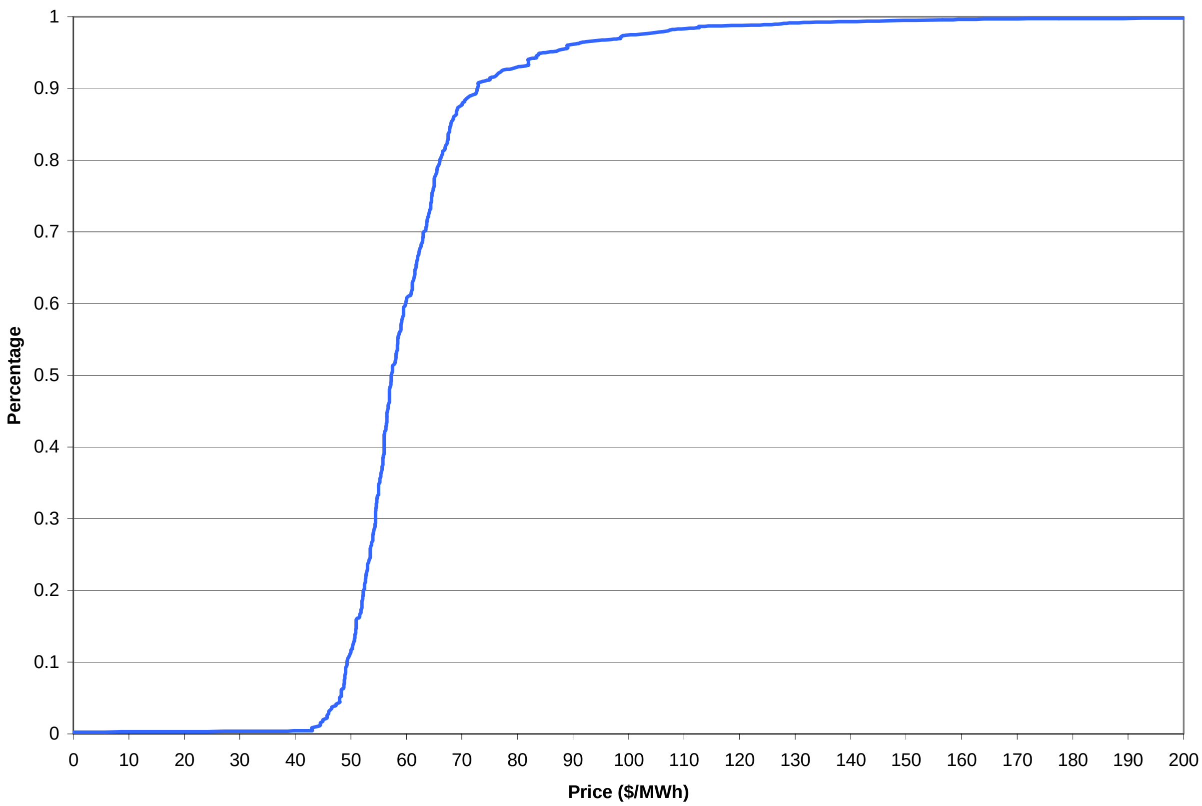


Figure 8. Price duration curve for Massachusetts Hub.
Source: Platts *Megawatt Daily*.

New York

Three New York ISO zones, Zones A, G, and J, are used for comparative purposes. Zone A is the western most region of New York and includes Buffalo and points south and west. Zone G is the Hudson Valley region just to the north of New York City. Finally Zone J is the New York City area. These three regions represent three levels of load and congestion.

Figure 9 shows the daily prices in Zones A, G, and J relative to one another as well as to the monthly average prices. As the graph shows, spikes in any one zone are generally accompanied by a corresponding spike in the other zones. These spikes differ in magnitude based on zone. Prices tended higher in January 2004 for all regions. January 2005, though lower in price than January 2004, also shows increased volatility relative to December and February.

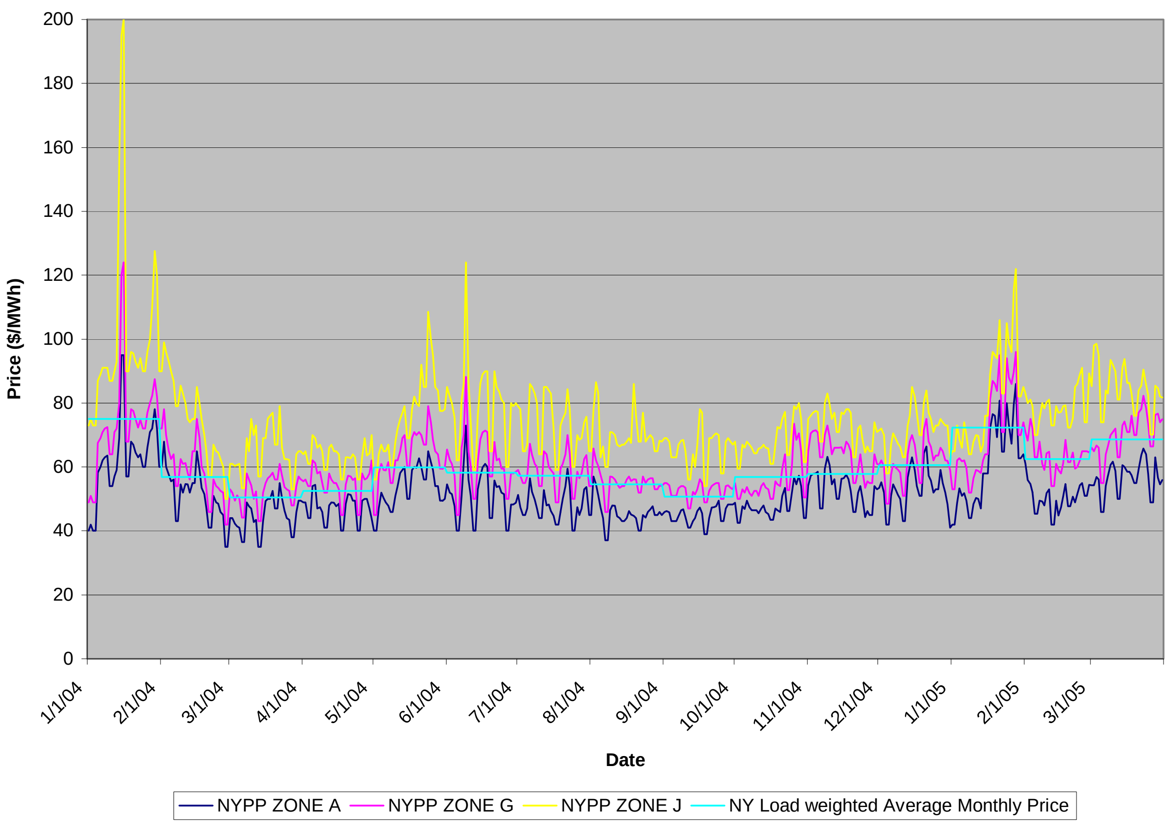


Figure 9. Daily volume weighted price for NYPP Zones A, G, and J and monthly average load weighted prices ($/MWh) for peak hours.
Souces: Platt's *Megawatt Daily* for Zones A, G, and J and NYISO for New York load weighted average monthly prices.

Figure 10 shows the average volume weighted average prices ($/MWh) for Zones A, G, and J. Prices in all three zones follow a similar price path, however they do so at very different price levels. These prices show trends of normal seasonal load in northern regions. That is, as demand fell in the spring and fall months, so did prices. However, prices rose gradually through the later fall and winter months. This increase is likely due to the increased need for natural gas during the heating season, which causes the price of natural gas to increase for electricity generation as well. It should be noted the Zone J (New York City area) had the highest average price for every month, while Zone A (western most zone in the state) had the lowest price in every month. Also, prices in Zone G (the Hudson Valley region) closely followed the prices for the day-ahead and real-time load weighted price for the entire state of New York.

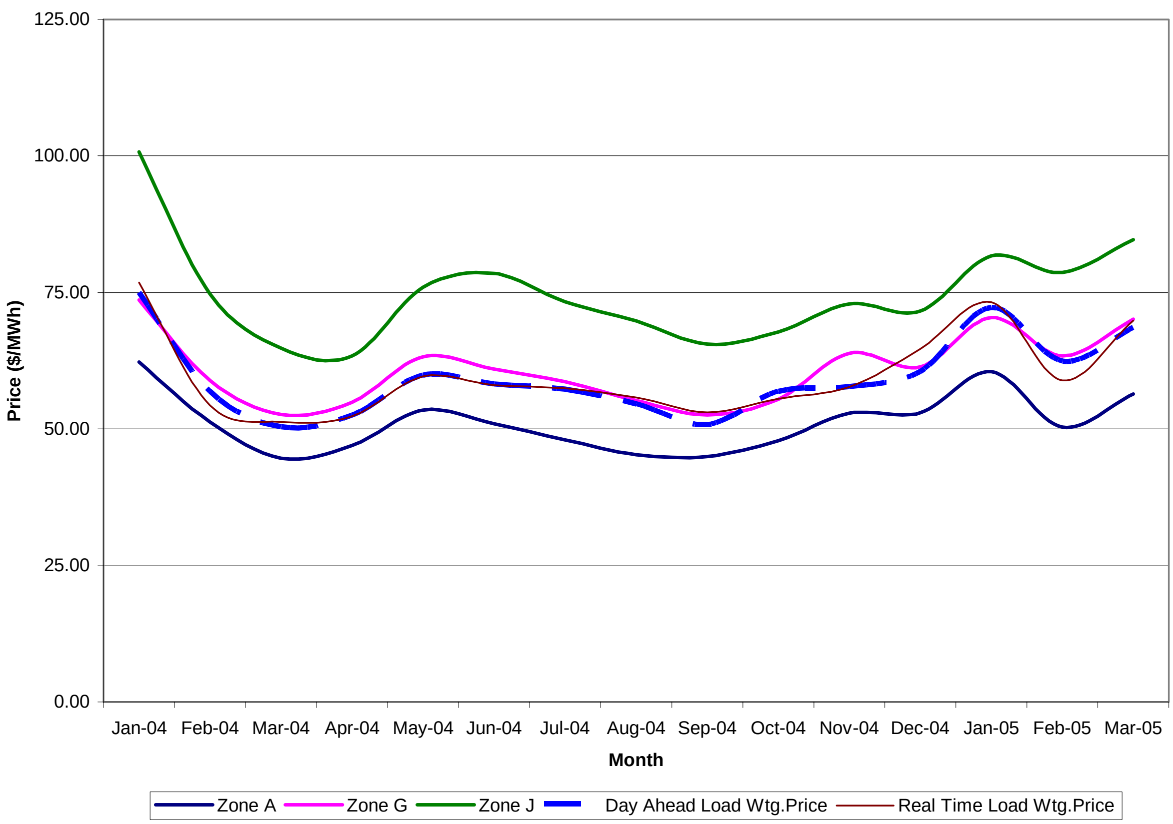


Figure 10. Monthly average volume weighted average prices ($/MWh) for peak hours. Souces: Platt's *Megawatt Daily* for Zones A, G, and J and NYISO for day-ahead and real-time prices.

Figure 11 represents the price duration curve for all volume weighted average prices for the three zones. Again, the price duration curve shows the range of prices in each region and what percent of the prices fell above or below a given level. The median price for Zone A is approximately $50, therefore; 50 percent of the prices in Zone A during peak hours fell below $50 for the time between January 1, 2004 and March 31, 2005. The median prices for Zones G and J were $60 and $73, respectively. The range of prices show that prices were reasonably stable. For Zone A, the middle 50 percent of prices (again, defined as 25 percent of the prices below the median, and 25 percent above the median) fell between $45 and $55. Zone G had a similar range, from $54 to $66, while Zone J had a range of $65 to $82. Finally, prices exceeded $100 for about 3 percent of the time in Zone J and less than 1 percent in Zone G.

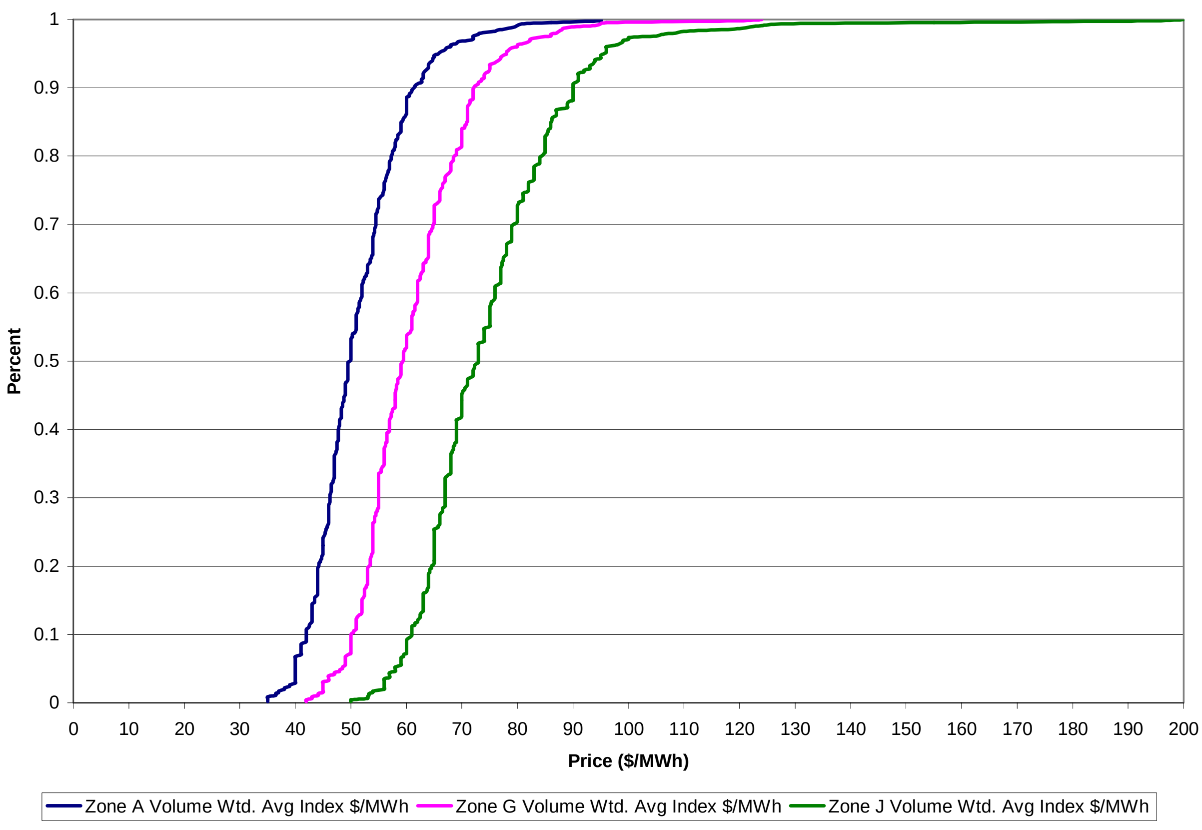


Figure 11. Price duration curves for NYISO Zones A, G, and J.
Source: Platts *Megawatt Daily*.

Midwest

Figure 12 shows the volume weighted price indices for Cinergy. With ComEd joining PJM, Cinergy is one of the major trading zones in the Midwest. Prices generally ranged between $30 and $60 for the time period examined. However, prices are showing slow increases over time, that likely reflect fuel price increases.

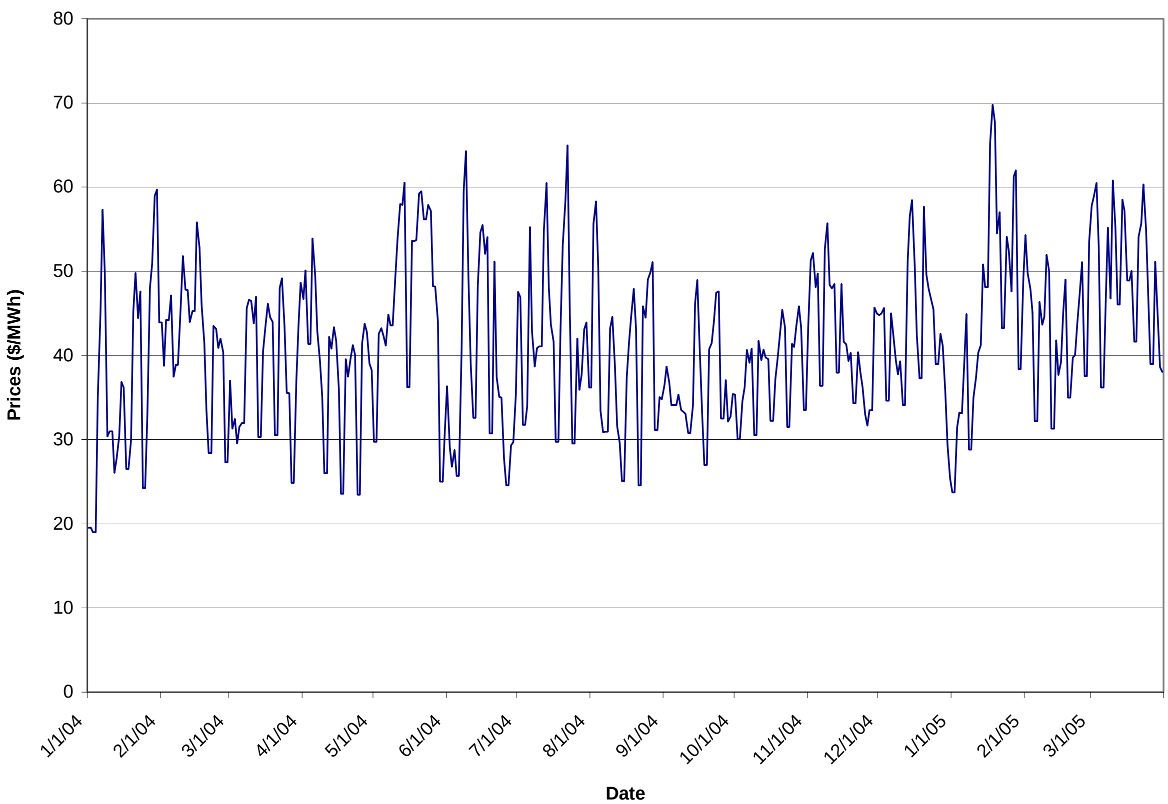


Figure 12. Daily volume weighted price indices ($/MWh) for Cinergy.
Source: Platts *Megawatt Daily*.

Figure 13 shows the volume weighted prices for five Midwest hubs. Price movements seem to be fairly correlated across hubs. Prices at these hubs usually ranged from $30 to $60, similar to Cinergy, however, prices tended to fall below $30 more than Cinergy. An overall trend of increasing prices, similar to Cinergy can also be observed.

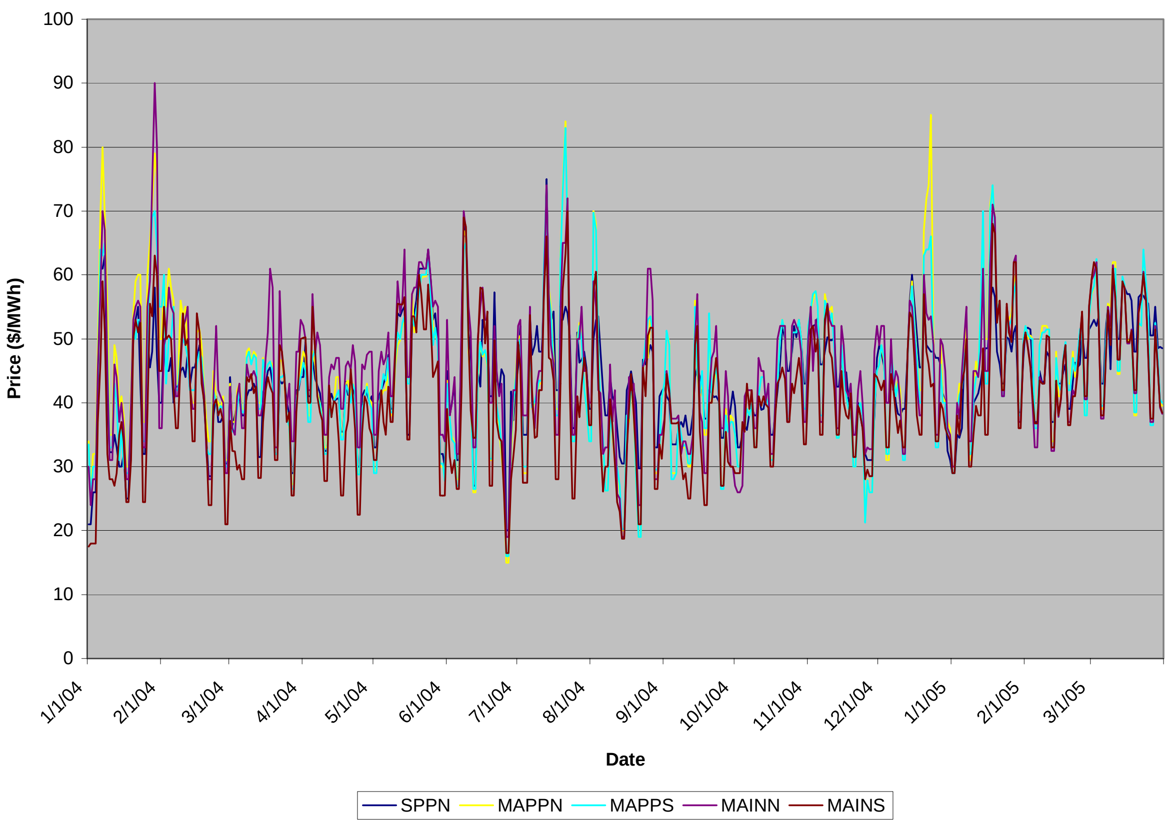


Figure 13. Volume weighted daily price indices ($/MWh) for five Midwest trading hubs. Source: Platts *Megawatt Daily*.

Figure 14 shows the monthly average prices for five Midwest hubs. Here the increase pricing trend is slightly more apparent. Prices fluctuated through August of 2004, and then began a steady increase that has covered the duration of the time period. Even though prices continue to rise, they are still in a similar price range (here, $40 to $50 monthly average) as they were at the start of the period.

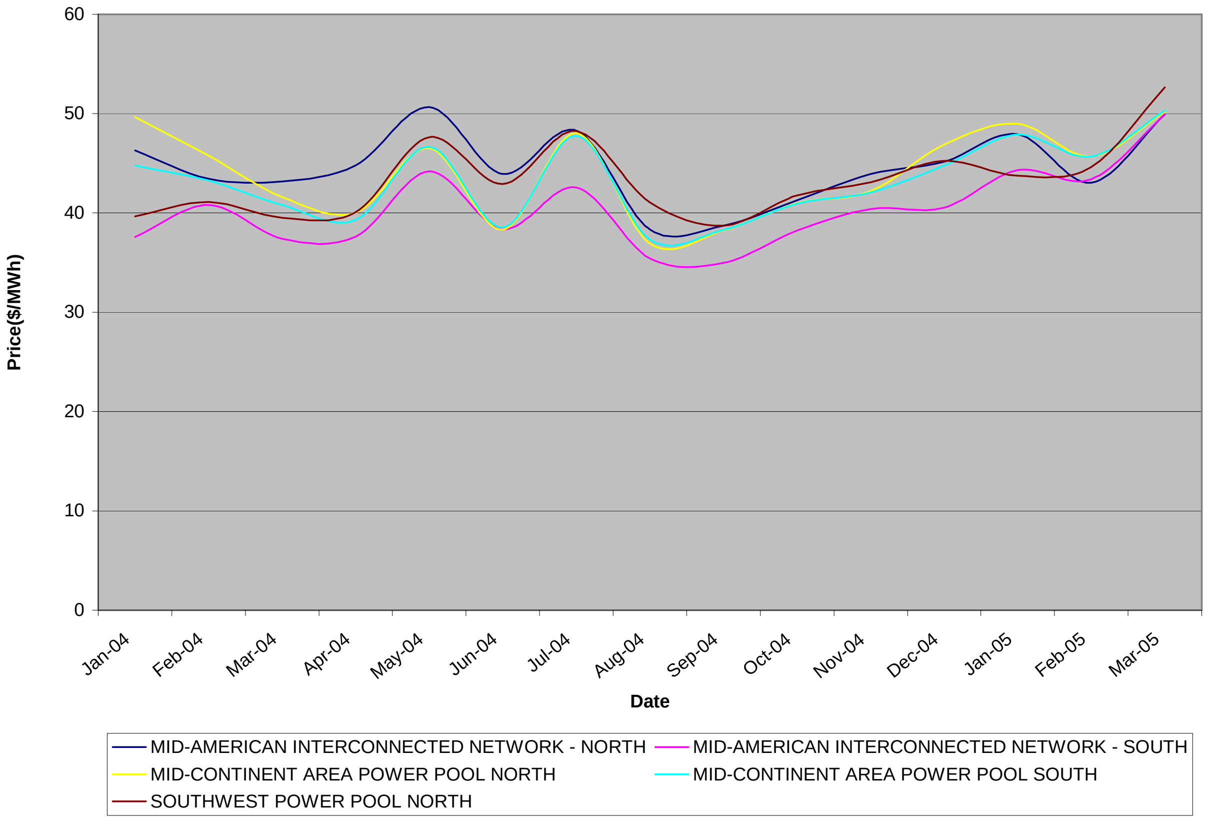


Figure 14. Monthly average daily volume weighted price indices ($/MWh) for five Midwest trading hubs.
Source: Platts *Megawatt Daily*.

South and Southeast

Figure 15 shows the volume weighted prices for four Southeast trading hubs. In Entergy, Southern and TVA, prices tended to range from \$30 to \$60, while Florida saw prices ranging from \$40 to \$70. Florida showed the highest prices on almost every day. Prices tended to be correlated across hubs.

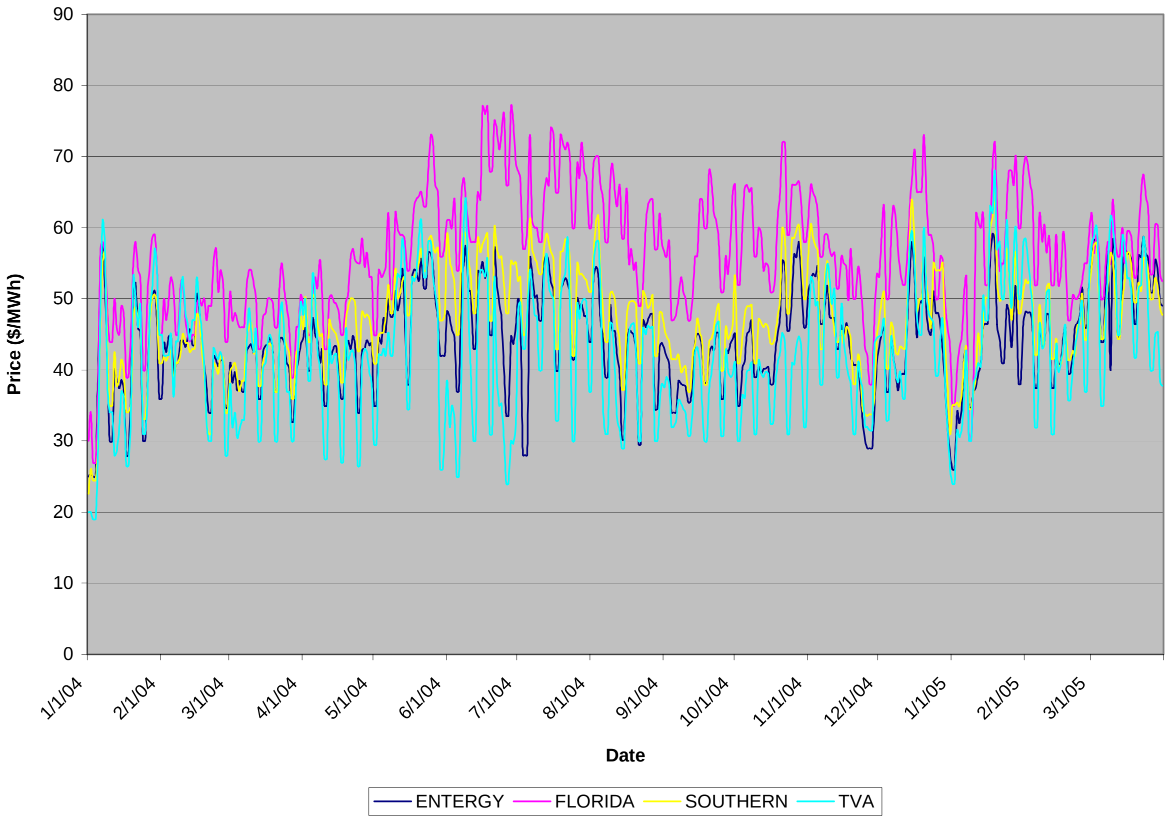


Figure 15. Daily volume weighted price indices (\$/MWh) for Southeast trading hubs. Source: Platts *Megawatt Daily*.

Texas

Figure 16 shows the daily volume weighted prices for the five zones in ERCOT. ERCOT serves about 85 percent of the Texas state electric load and is electrically isolated from other U.S. regions. Nearly all of the electricity consumed in ERCOT is also generated there. Between January 2004 and March 2005, prices tended to stay in the $40 to $60 range for all five regions. Due to the fact that ERCOT is isolated, prices in all the zones tend to move in conjunction with one another. In late October, there was a price spike where most of ERCOT saw prices soar from the low $40s to over $100.

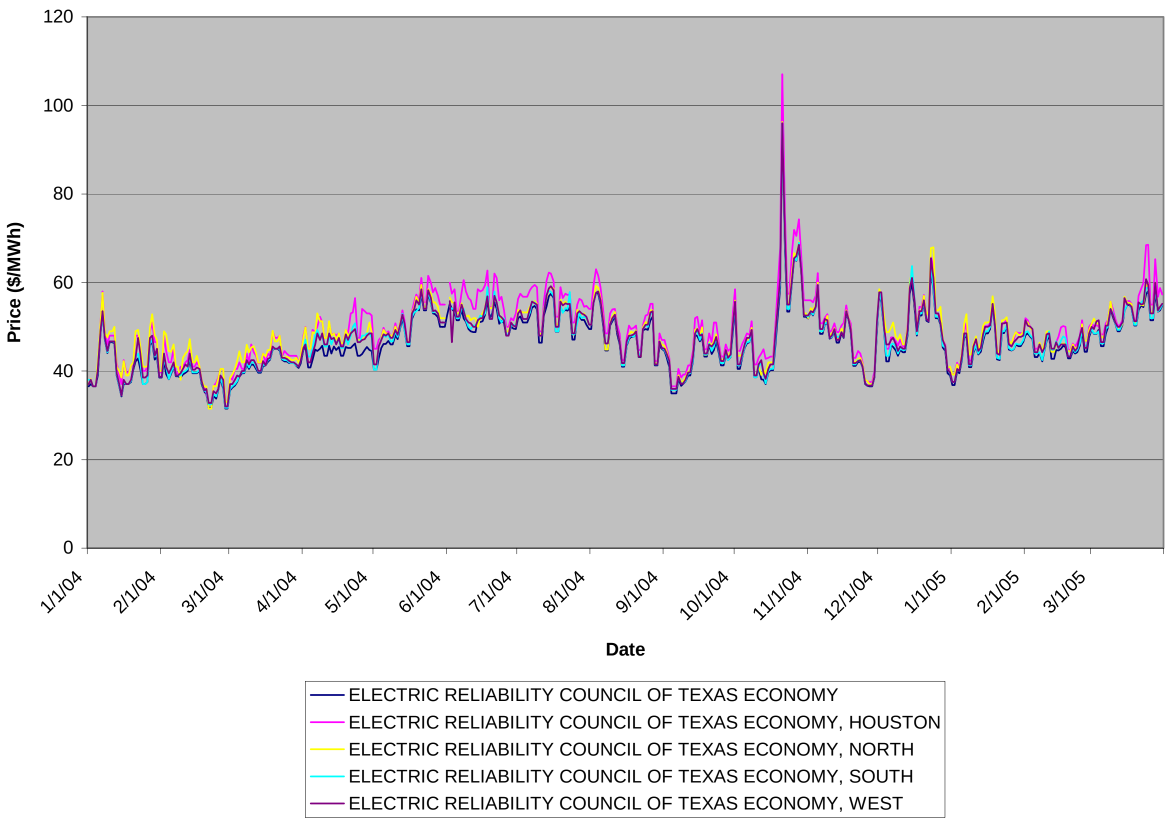


Figure 16. Daily volume weighted price indices ($/MWh) for ERCOT trading zones. Source: Platts *Megawatt Daily*.

Figure 17 shows the price duration curve for the five zones in ERCOT. As can be seen in the graph, median prices had a very small range. The region as a whole had the lowest median price at $46, while the Houston zone had the highest at $49. With exception of Houston, all zones had 90 percent of their prices fall at or below $55. Houston had 25 percent of the prices fall above $55. Rarely did the price fall below $39. The middle 50 percent of prices fell between $42 and $54.

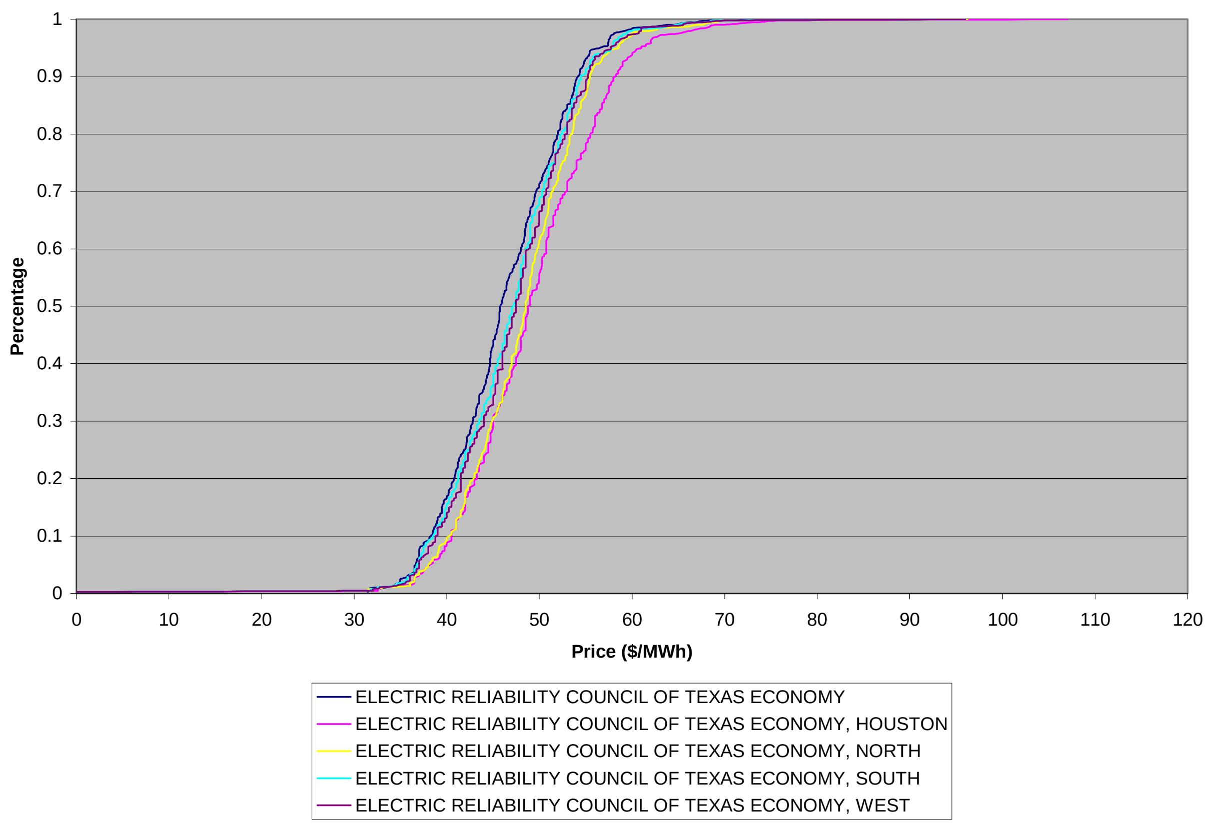


Figure 17. Price duration curve for daily volume weighted price indices ($/MWh) for ERCOT Trading Zones.
Source: Platts *Megawatt Daily*.

West

Figure 18 shows the volume weighted price indices ($/MWh) for the Western region. With the exception of Mead Nevada, most of the prices tend to move in the same direction. In June of 2004, all regions except Mead experienced a steady but dramatic drop in prices from the mid $50s to as low as $10 in Mid-Columbia (mostly hydro-power). However, prices rebounded by mid-June to the price level prior to the dip.

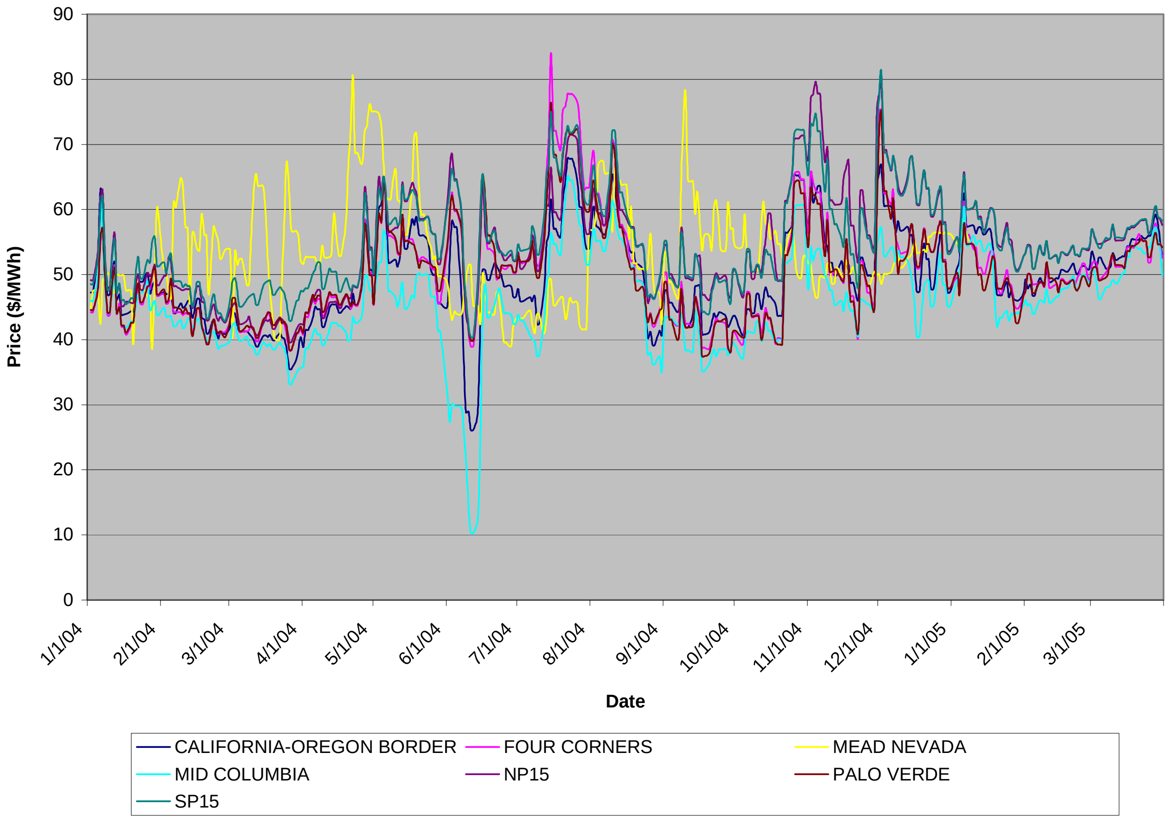


Figure 18. Daily volume weighted price indices ($/MWh) for the Western region. Source: Platts *Megawatt Daily*.

Figure 19 shows the price duration curve for the Western region. Price variation is similar for all regions. Mid-Columbia (again, mostly hydro-power) tends to show the lowest prices in the region, with a median price of $45 versus a median price of $54 for NP15 (which had the highest median price). For all regions, the middle 50 percent of all prices are in a $10 to $12 range above or below the median or a total range of $20 to $24.

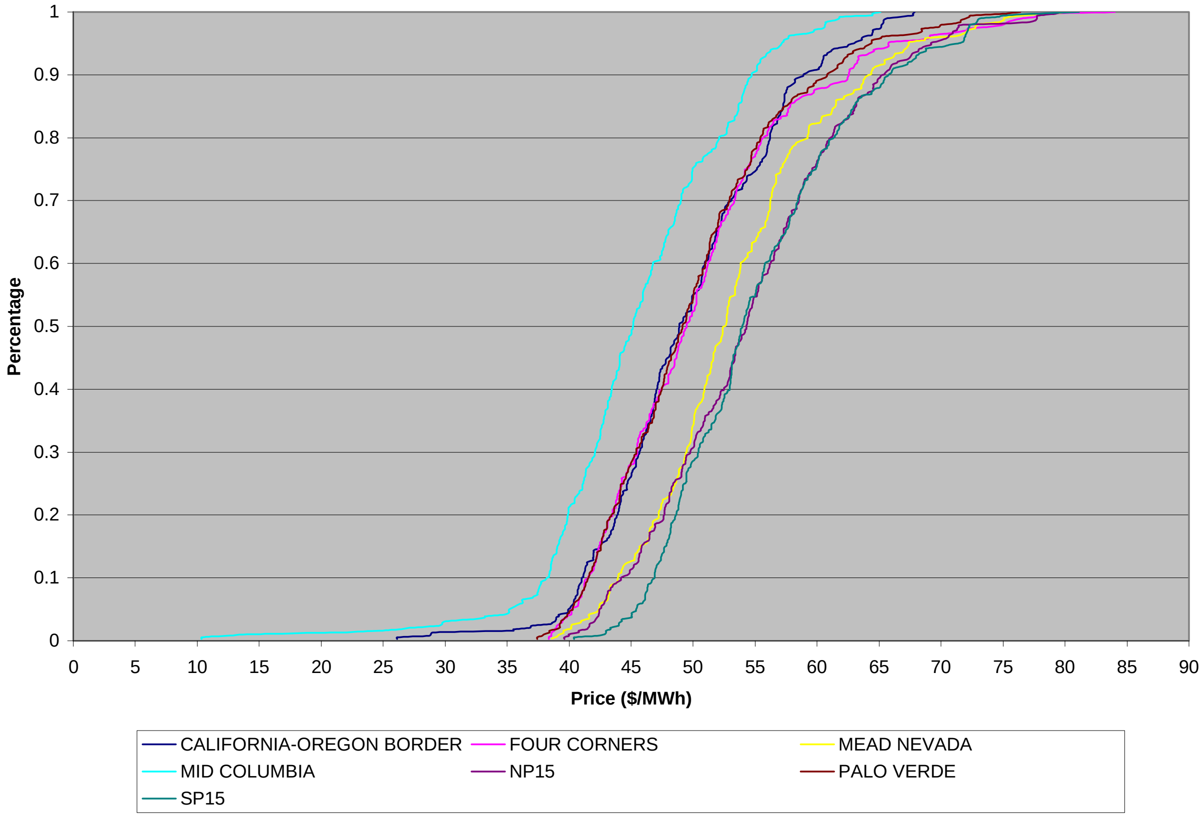


Figure 19. Daily volume weighted price indices ($/MWh) for the Western region. Source: Platts *Megawatt Daily*.

Retail Markets

Overview

At one point in the late 1990s, restructuring legislation had passed or was in various legislative stages of informal discussions, hearings, proposed legislation, or other activities in nearly every state. As summarized in Figure 20, currently, most states have decided to either postpone these efforts to implement retail access or have stopped considering adopting it altogether. Sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Two states allow retail access for larger

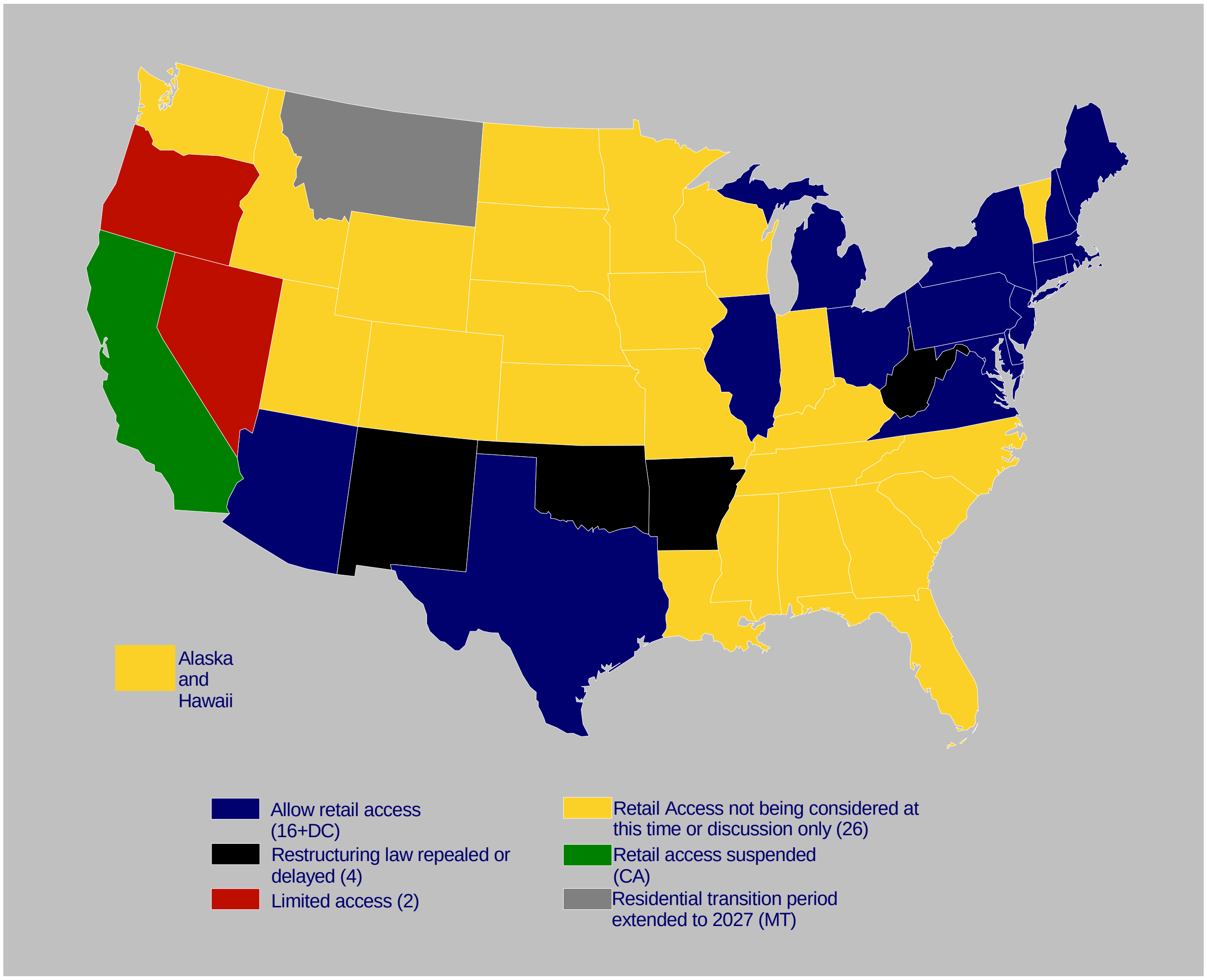


Figure 20. Status of state retail access.

customers only; Nevada, which modified its original law to limit access to just larger customers, and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation; Arkansas and New Mexico have repealed their laws; California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana has also been dealing with the severe aftermath of the western power crisis and extended the transition period to retail access for smaller customers. Montana implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002, was postponed to 2027.

Twenty-six states are no longer considering restructuring at this time. None of these states appear to be working in any meaningful way toward passage at this time. No state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. These states that did not pass legislation, but were in the process of considering it, either gradually lessened their efforts to allow time to consider what was occurring in the West, or they abruptly stopped any activity that was ongoing at the time. Thus, a total of 34 states have repealed, delayed, suspended, limited retail access to just large customers, or are now no longer considering retail access.

The single biggest factor stopping this activity was the price run-ups in California and the West beginning in mid-2000 until mid-2001. Also, following the western power crisis, the electric supply industry was beset by a series of other widely reported problems, including the Enron disclosures and collapse in late 2001, revelations of market price manipulation strategies, disclosures of accounting improprieties and data misreporting, the continuing "credit crunch," and the August 2003 blackout, the most extensive blackout in North American history. This is not to contend that all these events were directly due to electric restructuring, rather that these events caused sufficient concern among policy makers to cause them to rethink restructuring.

Retail Market Activity

Figure 21 shows the percentage of residential load that is supplied by an alternative supplier for 2004 and 2005. Only two states have percent of residential load “switching” greater than 10 percent in 2005. One state is Ohio where most of the residential switching in the state has been through the state's aggregation program. The other is Texas that is now the most active state in the country in terms of residential customers choosing a supplier. The reason for this will be discussed in the individual state summaries later in this section of this report. Most states are well below five percent. Nine states are at or near zero percent.

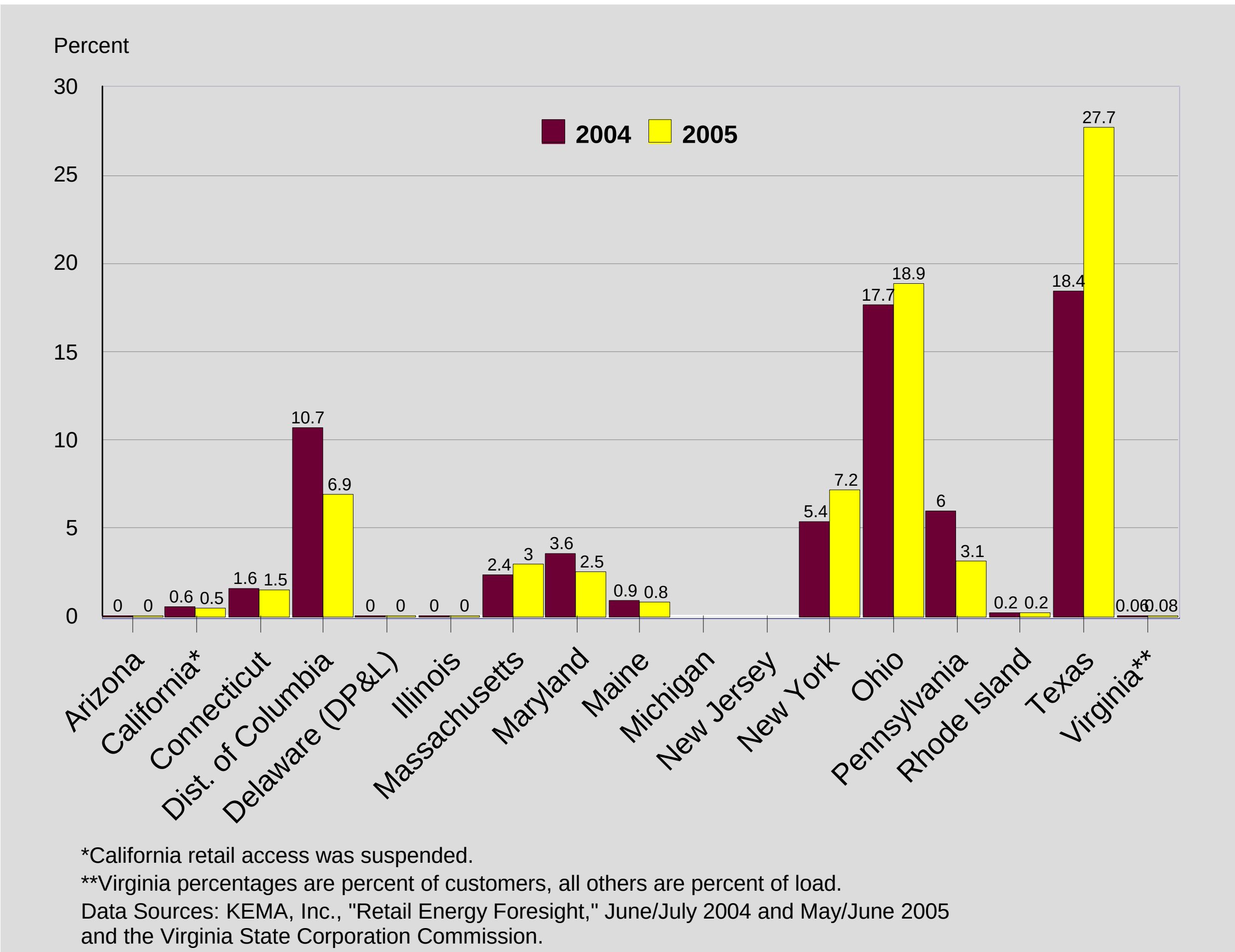


Figure 21. Percent of residential load served by competitive suppliers.

Figure 22 shows the percent of commercial and industrial load served by competitive suppliers in early 2005, which was considerably higher than for residential load. Six states, D.C., Illinois, Massachusetts, Maine, New York, and Texas, had a larger customer group (either commercial, industrial, or combined commercial and industrial) with greater than 50 percent of load served by competitive suppliers. Two were above 80 percent. Four states had no larger customer category above ten percent.

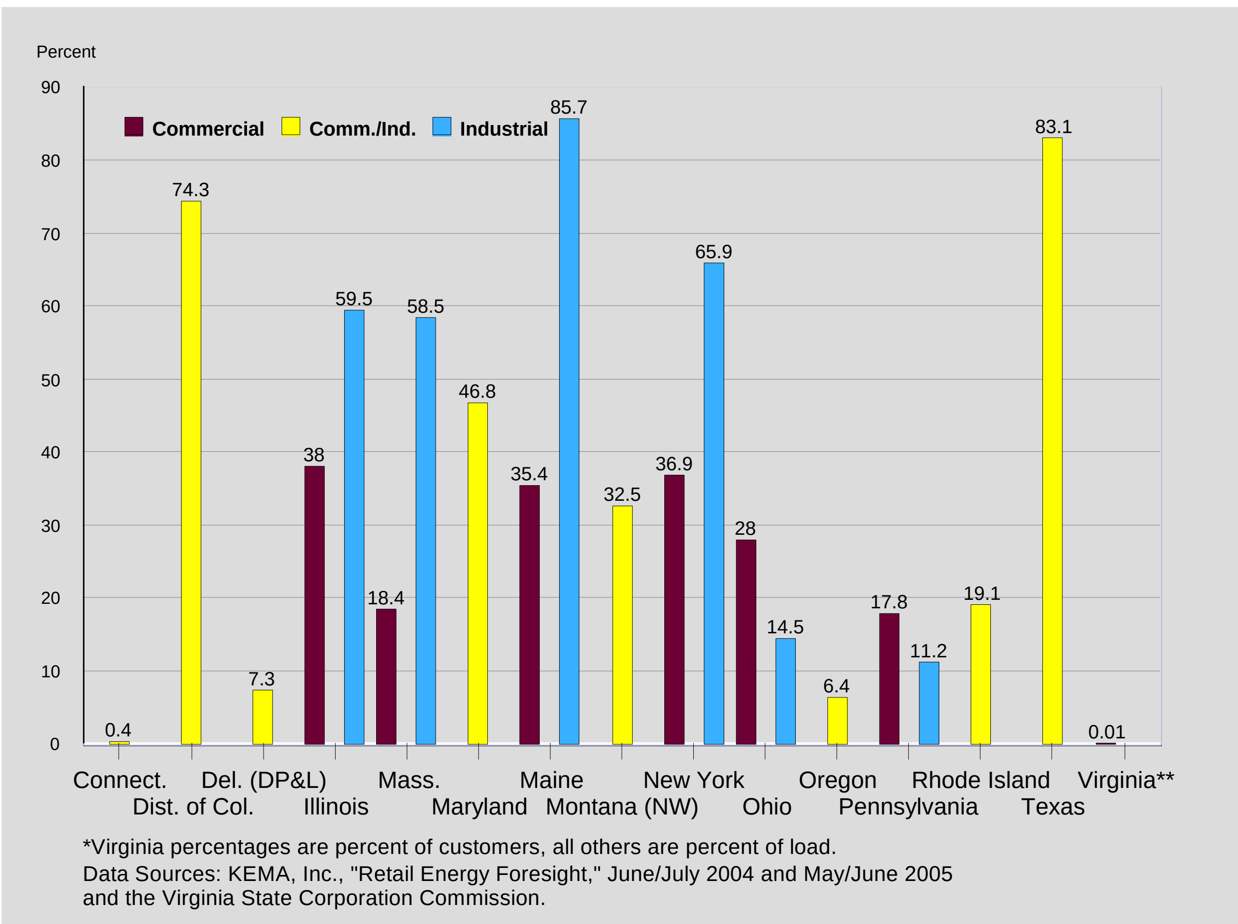


Figure 22. Percent of commercial and industrial load served by competitive suppliers.

Figure 23 shows the percent of total state load served by competitive suppliers for 2004 and 2005. Five state had greater than 30 percent of the total state load being served by competitive suppliers, D.C., Illinois, Maine, New York, and Texas. However, six states had less than ten percent of the total state load being served by competitive suppliers.

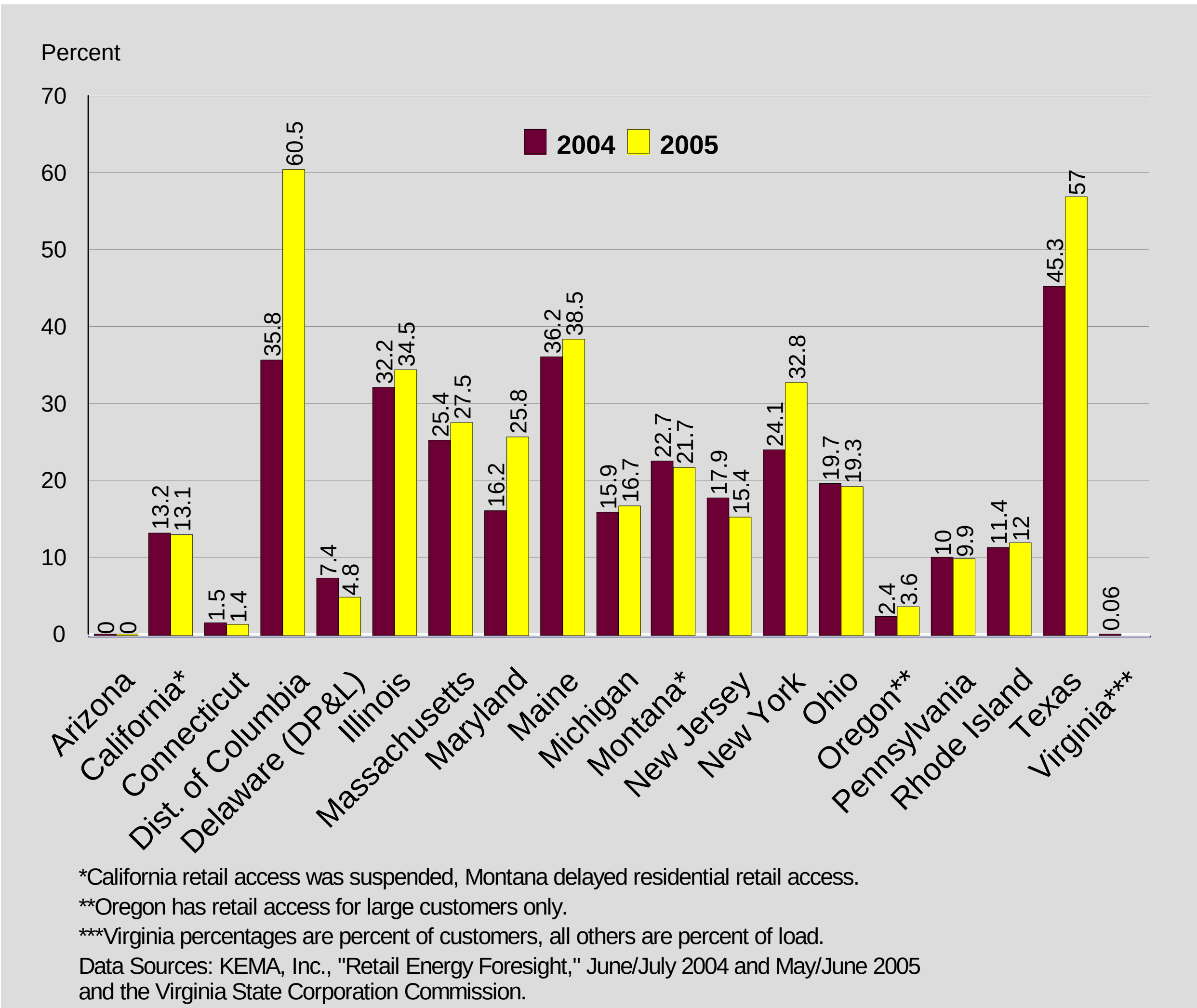


Figure 23. Percent of total state load served by competitive suppliers.

State Updates

The following are brief updates of several states that have had significant developments since last year's Performance Review. Following these summaries is a table (Table 3) that briefly covers 19 states and D.C., including all the states with full retail access for all customers groups.

New Jersey

The New Jersey Basic Generation Service (BGS) auction is an Internet-based, simultaneous multi-round descending clock auction. The auction determines the generation portion for customers that have not selected a supplier. A summary of how the auction works and past auction results are in last year's Performance Review. The results of the "fixed-price" BGS auctions (for smaller commercial and residential customers) are shown in Table 2. Comparing the first 12-month fixed-price BGS auction results in 2002 to the third 12-month auction in 2004, prices increased modestly for three of the four New Jersey companies involved, from about seven percent to just over nine percent, and decreased even more modestly, just over four percent, for the fourth company. Comparing the 34 month auction in 2003 with the 36 month auction in 2004, prices decreased slightly, from less than one percent for three of the companies to almost two percent for the remaining company. However, prices in the 2005 auction increased significantly above the 2004 auction. Comparing the 36 month auction in 2004 to the 36 month auction in 2005, prices increased over 18 percent for Public Service Electric & Gas, about 20 percent for Jersey Central Power & Light and Atlantic City Electric, and just over 28 percent for Rockland Electric. Nearly all the residential customers in the state receive basic generation service (see Figure 21).

It is important to note that auction price percentage increases do not directly translate to the same percentage changes in retail prices. This is because the auction is for determining only the generation component of the total retail price (which also includes distribution and other customer charges) and because of the mix of different contract lengths that remain in effect.

Table 2. Price results from the Fixed Price auctions for small and medium-sized customers in New Jersey, 2002 to 2005 (cents/kWh).

	2002 Auction	2003 Auction		2004 Auction		2005 Auction	Percent Increase 2004 to 2005
	12 month	10 month	34 month	12 month	36 month	36 month	
Conectiv/ ACE	5.12	5.260	5.529	5.473	5.513	6.648	20.6%
JCP&L	4.87	5.042	5.587	5.325	5.478	6.570	19.9%
PSE&G	5.11	5.386	5.560	5.479	5.515	6.541	18.6%
Rockland	5.82	5.557	5.601	5.566	5.597	7.179	28.3%

Source: New Jersey Board of Public Utilities, various years.

Maine

Maine has used a competitive bidding procurement process to determine the standard offer rates since 2000. The bidding process is conducted by the Maine Public Utilities Commission. Maine's restructuring law required complete divestiture of the utilities' generation assets and the distribution companies cannot participate in the bidding (affiliates of the distribution cannot provide more than 20 percent of the standard offer service in the company's service territory). The most recent bidding round for two companies, Central Maine Power and Bangor Hydro Electric, resulted in the standard offer rates from March of 2005 through February 2006 to increase by over 40 percent for both companies' residential customers. Nearly all the residential customers in the two companies' territories are on this standard offer rate for generation service. Prices for large and medium sized businesses will also increase in September of 2005 (see Table 3 for details).

Massachusetts

Massachusetts ended its "standard offer service" (the state's transitional generation service) and began "basic service" March 1, 2005, for residential customers that have not chosen a competitive supplier (almost 97 percent of the residential customers in the state). The distribution companies purchase electricity on the market following the procedures of the Massachusetts Department of Telecommunications and Energy. The rate increases for the six affected distribution companies in the state ranged from just over four percent for Massachusetts Electric Company to 28 percent for Western Massachusetts Electric Company.

Maryland

Maryland has a competitive bidding procurement process for small commercial and medium sized commercial and industrial customers on "standard offer service" for the four major electric distribution companies in the state and for residential customers of two distribution companies. The generation portion of the rate for residential customers of Potomac Electric Power (PEPCO) increased by 26 percent and the average annual bill increased by about 16 percent in 2004. For 2005, PEPCO’s residential customers generation standard offer will increase by 6.6 percent and the overall annual bill will increase by 4.6 percent. Delmarva Power and Light (DPL or Conectiv) residential customers had the generation portion of their bill increase by 19 percent and the average annual electric bill increased by about 12 percent in 2004. DPL customers in 2005 will have the generation component of their bill increase by 8.7 percent and the total annual bill will increase by 5.8 percent.

An Alcoa aluminum smelting plant, Eastalco Works near Frederick, Maryland, is facing much higher electricity prices when its contract with Potomac Edison/Allegheny Power (a distribution company of Allegheny Energy) expires on December 31, 2005. Eastalco is the biggest single electricity consumer in the state and accounted for 13 percent of Potomac Edison/Allegheny Power’s revenue in 2004. Electricity accounts for about one-quarter of the price of raw aluminum, and, at current power prices, Eastalco operators claim that the plant will have to be shut down, eliminating 639 jobs.[12] The parent company of Potomac Edison/Allegheny Power, Allegheny Energy, claims that

[12]“Alcoa Plant in Fredrick a Long Shot to Stay Open,” Jay Hancock, *Baltimore Sun*, June 15, 2005 and “Alcoa to Seek State Government’s Help to Limit Power Costs at Maryland Plant: Sharp Rate Increases Expected After Allegheny Contract Ends,” Associated Press, June 4, 2005.

the current special contract has been in effect since 1994, and that PJM average load-weighted wholesale prices have increased 83.5 percent from 1998 to 2004. Allegheny Energy also states that Potomac Edison/Allegheny Power is a delivery company and not an electric generation company that now obtains its electricity through the Maryland competitive bidding process. Allegheny Energy, that is an electricity supplier, only serves wholesale customers and does not serve retail customers.[13]

Over 92 percent of PEPCO residential customers and nearly all the residential customers of the other three major distribution companies in the state receive standard offer service.

Ohio

Ohio also attempted to find competitive suppliers for its standard offer generation service for the FirstEnergy Corporation companies that serve northern and parts of central Ohio. Ohio used an auction design similar to New Jersey's descending clock auction to test the rates agreed to in a "Rate Stabilization Plan" against a market price. The auction was held on December 8, 2004, and the Ohio Commission rejected the results of the auction the next day. FirstEnergy was then directed to implement the Rate Stabilization Plan pricing for standard offer service on January 1, 2006, that was previously approved by the commission. Another auction will be attempted in late 2005. The Ohio Commission has stated that the Rate Stabilization Plans agreed to with FirstEnergy (and other Ohio companies) are intended "to help ensure that electric consumers do not face ‘sticker shock' from electric rates when the market development period [the state's transition period] ends on December 31, 2005." They also noted that ". . . it was assumed that a regional market would develop quickly and that the retail markets would follow. . . . Thus far, the electric marketplace has not developed as hoped."

[13]“Facts on Allegheny Energy and The Competitive Electricity Market in Maryland,” Allegheny Energy, June 3, 2005.

Texas

Another state that is of considerable interest is Texas. Texas has been very assertive in the state's development of both wholesale and retail markets. Due to early success in terms of alternative retail suppliers that have offered prices below the utility "price-to-beat" rate and customer switching activity to these alternative suppliers, Texas is often depicted as a success for retail competition. The price-to-beat is used by customers to compare alternative suppliers. The price-to-beat rate is administratively set (not by a competitive procurement process) by the Public Utility Commission of Texas and is adjusted to reflect changes in natural gas and purchased energy market prices.

Since retail access began in Texas on January 1, 2002, the residential price-to-beat rates have increased substantially for customers in the five investor-owned companies' service territories in the ERCOT region of the state. Between January 2002 and March 2005, the price-to-beat rate has increased by just over 30 percent in TXU Electric & Gas, nearly 38 percent in Central Power and Light and Texas-New Mexico Power, and almost 45 percent in Reliant Energy and West Texas Utilities. About 80 percent of residential customers are paying the price-to-beat rate. The residential price-to-beat rates from January 2002 to March 2005 in the five Texas service territories with retail access are shown in Figure 24.

The increases in the price of natural gas over the last few years explain why the price-to-beat rates have also been increasing. However, an analysis of rates of different companies across the state shows that rates increased on average 43 percent from January 2002 to October 2004 for customers of the restructured utilities, but rates for customers of non-restructured and still regulated utilities increased by 17 percent and rural electric cooperative rates increased by 9 percent.[14] The price of natural gas is being used to adjust the rates to reflect the marginal cost of producing power in the state, in order to simulate a market outcome. But under cost-based regulation, the rate

[14]As reported in "Electricity up more in deregulated areas of Texas," *Fort Worth Star-Telegram*, Texas Knight Ridder/Tribune Business News, April 19, 2005 and "Texas Electricity Deregulation Hasn't Aided Small Power Users," *The Wall Street Journal*, May 20, 2005.

is adjusted for the portion of generation that uses natural gas and for other costs that may have increased or decreased as well, in proportion to actual or expected utilization.

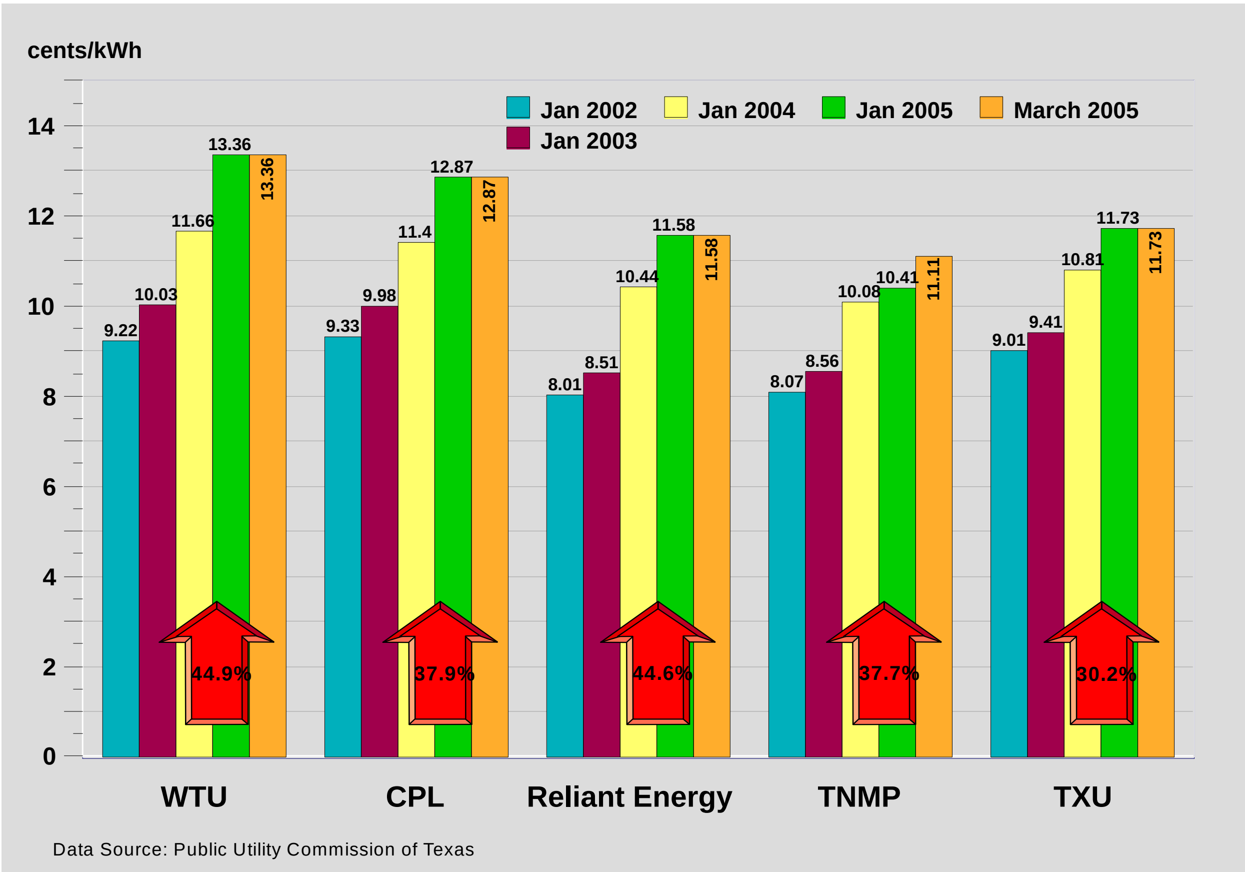


Figure 24. Residential "Price-to-Beat" rates in five Texas service territories and percentage increases, January 2002 to March 2005.

Summary of State Restructuring Activity

Table 3. State restructuring summary.

State	Investor-owned utilities/distribution companies	Restructuring legislation	Discounts
	Updates of Interest		
Arizona	Arizona Public Service Company (APS) and Tucson Electric Power Company (TEP)	Restructuring legislation passed in 1998. Retail access began January 1, 2001.	
	In 2002, the Arizona Corporation Commission (ACC) eliminated the requirement that utilities divest generation assets and that all power needed for standard offer service be purchased in the market. In an April 2005 Order, the ACC authorized APS to place generation assets into rate base. Retail access is allowed, however, rates were determined in a way that more closely resembles traditional regulation. Arizona's retail market was just beginning in January 2001 when the western power crisis was about at its peak. The interest that competitive suppliers had at the beginning disappeared and there are currently no shopping customers in the state, except large industrial customers on special contracts.		
California	Pacific Gas and Electric Company, Southern California Edison, San Diego Gas and Electric	Restructuring law passed in 1996. Retail access began April 1998.	Restructuring legislation required a 10% rate cut.
	In September 2001 retail access is suspended by the PUC.		
Connecticut	Connecticut Light & Power and United Illuminating	Restructuring law passed in 1998, revised June 2003.	Legislative discount: 10% below the 1996 rates, same rates in effect in 1999.
	Original Standard Offer service set to run from January 1, 2000 through December 31, 2003, for residential and small business customers. Revised restructuring law created the "Transitional Standard Offer Period," in effect from January 1, 2004 through December 31, 2006 – ended 10% rate reduction. Standard Offer rate increased 10.3% on January 1, 2005.		

Delaware	Delmarva Power & Light Co. (Conectiv Power Delivery) and Delaware Electric Cooperative (DEC)	Restructuring law passed March 1999. Retail access phased-in beginning October 1, 1999 for large Conectiv customers and ended April 1, 2001 when all customers were eligible. Rate freeze extended to March 2006 as part of merger of PEPCO and Connective and March 2005 for DEC.	Residential rate cut of 7.5% for Conectiv customers and a rate freeze for Delaware Electric Cooperative customers.
	Rate caps end for Delmarva Power & Light Co. customers on May 1, 2006, were originally set to end September 2003, but were extended by merger resolution. Rate caps ended on March 31, 2005, for Delaware Electric Cooperative customers. In March 2005, the Commission approved Delmarva Power & Light Company as the Standard Offer Service supplier for after May 1, 2006 – customer prices will be determined by a competitive bidding (RFP) process and in the wholesale market. Commission approved a settlement also in March 2005 that established new rates for Delaware Electric Cooperative customers – for residential customers the supply rates increased approximately 14.5% and distribution rates decreased approximately 24%, resulting in almost no overall rate change.		
District of Columbia	Potomac Electric Power (PEPCO)	Restructuring legislation passed 1999. Retail access began January 1, 2001.	The Commission in 1999 approved a reduction in PEPCO's residential rates by 7% between January 1, 2000 and February 7, 2001, and capped at the reduced levels through February 7, 2005. Electric rates for customers who participate in PEPCO's Residential Aid

			discount ("RAD") program are capped until February 2007.
	*PEPCO's distribution service rates are capped until August 2009 for RAD customers and until August 2007 for all other customers. PEPCO (which sold all its generation plants by January 2001) is required to procure wholesale generation through a competitive bidding solicitation that is overseen by the Commission. Beginning February 2005, bills for most residential customers in DC increased on an average annual basis by approximately 18%, or about $10.00 per month. Residential bills increased approximately 26% during the winter and 9% during the summer. Small commercial customer rates increased by approximately 24% on average for the year.		
Illonois	Central Illinois Public Service Company (AmerenCIPS), Central Illinois Light Company (AmerenCILCO), Commonwealth Edison, Illinois Power Company (AmerenIP)	Restructuring law passed in 1997. Retail access phased-in, beginning October 1,1999, retail access for residential customers began on May 1, 2002. Transition period until January 2007.	15% in 1998 and an additional 5% for Commonwealth Edison and Illinois Power residential customers. Smaller discount for customers in other areas.
	The Illinois restructuring legislation's transition period ends on December 31, 2006. To prepare for this, the Illinois Commerce Commission (ICC) hosted a series of workshops called the "Post 2006 Initiative," in 2004 to discuss the states competitive options. Currently, before the ICC, are proposals from the Ameren companies and Commonwealth Edison to conduct New Jersey-type "BGS" auctions for power procurement after the transition period ends. There is no residential shopping in Illinois and, as noted in a December 2004 ICC staff report, "no alternative supplier has even applied for certification to serve residential customers."		
Maine	Bangor Hydro-Electric, Central Maine Power, Maine Public Service Company	Restructuring law passed in May 1997. Retail access began March 2000. All standard offer prices determined by a bidding process.	Rate Reductions from 2.5% to 15%

	*In December 2004, the Maine PUC accepted bids approximately 40% higher for standard-offer service (SOS) generation service starting in March 2005 through February 2006 for small commercial and residential customers. The new prices reflect current wholesale energy prices which have risen substantially since SOS prices were set 3 years ago. More than 99% of Maine's residential and small commercial load is currently supplied by SOS. Prices for large and medium sized businesses will increase in September, following bids accepted by the Maine Public Utilities Commission. The bids were for new standard-offer energy prices for medium and large commercial and industrial customers of Central Maine Power Co. and Bangor Hydro-Electric Co. They cover a six-month term beginning Sept. 1. For CMP customers, the new prices are about 8.3 cents a kilowatt hour for both the medium (up 22%) and large (up 27%) classes. For Bangor Hydro customers, the average prices are about 8.5 cents/kwh for the medium class (up 23%) and 7.8 cents/kwh for the large class (up 24%). The rate increases reflect the higher prices charged by power generators, not the delivery services offered by CMP and Bangor Hydro-Electric. The increases are tied to the cost of imported fuel in New England, the PUC said. They also may reflect potential capacity costs pending before federal energy regulators. Standard-offer service is the default supply for customers that don't purchase energy from a retail supplier or through an aggregator. Roughly 15 percent of the electric load of CMP and Bangor Hydro's large customers, and 65 percent of medium customer load are supplied by standard-offer service. Source: "Electric rates to rise sharply for larger businesses in Maine" Knight Ridder/Tribune Business News - Tux Turkel, Portland Press Herald, Maine.		
Maryland	Allegheny Power (APS), Baltimore Gas & Electric (BG&E), DPL/Connectiv (DPL), Potomac Electric Power Company (PEPCO)	Restructuring law passed in April 1999. Residential transition ends July 1, 2008 for Allegheny Power (APS) and July 1, 2006 for Baltimore Gas & Electric (BG&E). Transition ended July 1, 2004 for DPL/Connectiv (DPL) and July 1, 2004 for Potomac Electric Power Company (PEPCO).	APS: About 7% reduction for residential, BG&E: 6.5% reduction for residential, DPL/Connectiv: 7.5% reduction for residential, PEPCO: 3% reduction for residential.
	*July 1, 2004, all Standard Offer Service price caps remaining for non-residential customers were lifted. SOS caps were lifted for residential DPL and PEPCO customers in July 1, 2004. * On April 2, 2004, the Maryland Public Service Commission (PSC)		

	announced the results of a bidding process secured electric suppliers to provide market priced electric Standard Offer Service for Maryland customers of investor owned electric companies whose fixed price electric service offerings are expiring. The process was established with the PSC's Order No.'s 78400 and 78710 (in Case No. 8908), which set the rules for Standard Offer Service procurement, pricing methodology, and technical details of the bidding process. The bidding rounds began in February and concluded in March. Supply services under these contracts began June 1, 2004. (See Maryland section of text for 2005 results.)		
Massachusetts	Boston Edison, Cambridge Electric, Commonwealth Electric, Eastern Edison, Fitchburg Gas and Electric, Massachusetts Electric Company, Western Massachusetts Electric Company.	Restructuring law passed in November 1997. Retail access began March 1998. Transition until March 1, 2005.	Discount of 10% for all standard offer customers.
	*Standard Offer Service (SOS) expired February 28, 2005. SOS rates increased approximately 7.5% as customers were shifted to default rates. Default rates are set every six months (see Massachusetts section in text).		
Michigan	Alpena Power Company, American Electric Power Company, Edison Sault Electric Company, Detroit Edison Company, Consumers Energy Company	Restructuring law passed in June 2000. Retail access began January 1, 2002. Transition rate caps until January 2004.	5% rate reduction through the end of 2003 for every residential electric customer of Detroit Edison Company and Consumers Energy Company.
	*Per state law as of January 1, 2005 all member owned co-op customers now also have open access to suppliers.		
Montana	Montana Dakota Utilities, Energy West Montana, and Northwestern Energy	Restructuring law passed in 1997. Retail access began 1998 (for large customers). In 2001 - transition period	2 year rate freeze began July 1998.

		extended to 2007. In 2003 - transition period extended until 2027.	
	*On November 1, 2004, NorthWestern Energy emerged from Chapter 11 bankruptcy. The company disposed of many non-utility assets, simplified its corporate structure and reduced overhead costs. The Company's debt was reduced from $2.2 billion to approximately $850 million including the effects of refinancing. Legislation extended the transition period for residential customers to July 1, 2027.		
New Hampshire	Public Service Company of New Hampshire (PSNH), Granite State Electric Company (GSEC), Unitil Energy Systems, Inc. (UES), and New Hampshire Electric Cooperative, Inc. (NHEC).	Original restructuring law passed in 1996. Retail access implementation was delayed by litigation. GSEC began retail access August 1998, PSNH began May 2001, and UES companies began May 1, 2003.	10% rate reduction for PSNH residential customers.
	*The Public Utilities Commission approved a proposal in November 2003 that encourages large commercial and industrial customers to switch from PSNH to electricity purchased from competitive suppliers. The Retail Energy Services, or RES program, was designed for customers whose billing demand is one megawatt or greater. If they agree to join, such customers may choose a supplier and receive a per-kilowatt-hour credit against the energy portion of their electric bills. It is hoped that this credit will provide incentive to a customer to switch to a competitive supplier. Currently, the transition service price is lower than the market price for electricity, so there is no incentive for customers to switch. The RES program is designed to encourage comparison shopping. It went into effect on February 2004 and will end after two years. Most residential customers receive Transition Service.		
New Jersey	Connectiv, GPU/ FirstEnergy Company - Jersey Central Power & Light, PSE&G, Rockland	Restructuring law passed in February 1999. Retail access began August 1999. Transition ended August 2003.	5% in 1999 and an additional 10% over the next 3 years.

	*New Jersey regulators okayed an electricity buying plan for the state's four utilities in November 2002. According to the plan, the Board of Public Utilities (BPU) will conduct two auctions. The first will provide energy at hourly prices to large industry and business customers. The second will be a fixed-price auction (or "Basic Generation Service" auction) to provide energy to homeowners and small businesses. This multi-phased plan went into effect August 1, 2003 and will conclude on May 31, 2006. (Details on past auctions are in last year's Performance Review, pp. II-17 to II-23.) *The state Board of Public Utilities (BPU) voted a rate increase for Public Service Electric & Gas Company (PSE&G) customers in July 2003. This vote, together with the end of price controls in August 2003, caused electric rates to increase by as much as 15 percent for customers of PSE&G. The result was that rates reverted to approximately the same level as when the deregulation act went into effect in mid-1999. The total cost of power purchased in the seven day February 2004 auction (as certified by the Board of Public Utilities) amounted to an estimated $5.1 billion, resulting in lower electric rates and a savings of $24 million for ratepayers annually. Most of New Jersey's 3.2 million residential customers had their bills drop by anywhere from $0.43 cents to $1.02 per month beginning in June 2004. (NJ Consumer Advocate) See New Jersey summary in text for the 2005 auction results. FERC approved Excelon/PSEG merger in July 2005 – other agency decisions are still pending (including the NJBPU).		
New York	Central Hudson, Consolidated Edison, New York State Electric and Gas, Niagara Mohawk Power Company, Orange & Rockland Utilities, Rochester Gas and Electric	Restructuring implemented by Commission orders, no restructuring law passed. Retail access and transition periods differ by company. See below.	Discounts differed by company. See below.
	*The New York State Public Service Commission (PSC) initiated deregulation discussions with each investor-owned utility individually. The PSC approved utility restructuring plans that dealt with rate levels, retail competition, and corporate restructuring of all of New York's seven major electric utilities. The transition to competition began in 1998 for the utilities with approved plans. Each plan is different.		

From DOE **“**Status of State Electric Industry Restructuring Activity” 2003

Central Hudson Gas & Electric

Retail access began: September 1998

Rates frozen at 1993 levels until June 30, 2001

Full Retail Access - July 1, 2001

Consolidated Edison

Retail access began: June 1, 1998

25% rate reduction for 5 years for large industrial, 10% for all other customers phased in over 5 years

Full Retail Access – December 2001

Long Island Power Authority

January 2002: LIPA opened up the Long Island electricity market completely on January 17, 2002, seven years ahead of schedule. LIPA is not subject to PSC rate regulation.

New York State Electric & Gas

Retail access began: August 1, 1998

Rates capped until 2003, after 2003, delivery rates are regulated by the PSC, while energy rates will be set by the market. Also a 5% rate reduction for industrial and large commercial consumers for five years (five reductions of 5% each), and residential and small commercial/ industrial consumers received 15% reduction by third year and 5% by the fifth year.

Full Retail Access - August 1,1999

Niagara Mohawk Power

Retail access began: September 1, 1998

Residential and commercial customers received a 3.2% phased in decrease over three years. Industrial received about a 13% phased in rate reduction. Rates for electricity and delivery were set until September 2001. Rate changes after that period must go through the PSC.

Full Retail Access - August 1, 1999

As part of merger agreement when National Grid bought Niagara Mohawk “calls for National Grid to lower electricity prices and freeze natural gas delivery rates for 10 years.” Essentially increasing the transition to 2011.

Orange and Rockland Utilities

Retail access began May 1, 1998

Rates fell by 4%, 4%, and 14% for residential, commercial and industrial respectively in 1995-1996. This was followed by two 1% reductions, in 1997 and 1998, for residential costumers and a 8.5% drop in 1997 for large industrial customers.

Full Retail Access - May 1, 1999 includes energy and capacity

Rochester Gas & Electric

Retail access began July 1, 1998

	Rates set until mid 2002, residential, commercial, and industrial consumers received 7.5%, 8%, and 11.2% rate reductions, respectively, to be phased in over five years. Full Retail Access - July 1, 2001, includes all customers, energy and capacity. Delivery charges are regulated by the PSC, energy prices are determined by the market. **On August 25, 2004, the Commission adopted the Statement of Policy on Future Steps Toward Competition in Retail Energy Markets. The Policy Statement sets forth the Commission's goals and visions for the further development of robust retail energy competition in New York and provides a flexible framework for the Commission to analyze and respond to evolving market conditions and thereby to facilitate market development as required. Central Hudson's was approved May 2005.		
Ohio	AEP/Columbus Southern Power Company, AEP/Ohio Power Company, Cincinnati Gas & Electric Company, Dayton Power and Light Company (DP&L), First Energy/Cleveland Electric Illuminating Company, First Energy/Ohio Edison Company, First Energy/Toledo Edison, Monongahela Power Company	Restructuring law passed in July 1999. Retail access began January 1, 2001. Original transition until December 31, 2005 and through Dec 2003 for DP&L – later extended to Dec 2005. Extended transition through Dec 2008 for AEP and FirstEnergy companies.	5% rate reduction on generation portion and 5 year rate freeze (was to end December 2005), except DP&L (3 year freeze, and 5% reduction, then in 2.5% reduction of generation costs starting in 2006 and lasting 3 years). AEP extended 3 years (through 2008), allowed 3% increase per year. FirstEnergey Rates are frozen until 2008 except fuel and tax adjustments.

	*Most retail activity has been in the northern part of the state (the area served by the FirstEnergy companies). That area has historically had higher prices in the state. Most residential switching customers have used the Community Choice aggregation option available through the state. The rest of the state has shown almost no movement of residential customers. *Though Dayton Power and Light Co (DP&L) was to start charging market prices for power in January 1, 2004, fears of volatile rates caused certain public-interest groups to make a deal with the company, freezing distribution rates through 2008. The plan will allow DP&L to file for rate increases in 2006 to pay for higher costs. **Rate Stabilization Plans extended for First Energy, AEP, DP&L, and Cinncinati Gas & Electric. AEP Extended for three years staring Jan 2006 and can increase generation charges by 3% for all customer classes. ** The Public Utilities Commission of Ohio (PUCO) adopted a Rate Stabilization Plan (RSP) for FirstEnergy that provided for a competitive bidding process, or auction, to be conducted on FirstEnergy's electric load to see if lower rates could be obtained. The auction was conducted in December 2004. The PUCO rejected the results of the auction, finding that the RSP provided lower electricity rates. The PUCO will hold additional auctions in the future to continue to test the market for lower generation rates. **Monongahela Power chose not to file an RSP. Instead, the company filed an application to implement a fixed and variable rate, market-based standard service offers to be determined by a competitive bidding process. On June 14, 2005, the PUCO directed Monongahela Power and AEP to pursue potential terms and conditions for transferring Monongahela Power's Ohio territory to AEP. In August 2005, Allegheny Power (the delivery company of Allegheny Energy, that includes Monongahela Power) announced an agreement to sell its Ohio service territory's transmission and distribution assets to American Electric Power's Columbus Southern Power subsidiary for net cash proceeds of approximately $55 million.		
Pennsylvania	Allegheny Power, Duquesne Light, Metropolitan Edison, PECO Energy, Pennsylvania Energy, Pennsylvania Power, Pennsylvania Power and Light, UGI Utilities	Restructuring law passed in December 1996. Retail access phased in beginning January 1999 and reached all customers by January 2001.	No required reductions in legislation, some companies had them in first year and phased out over three years.

	*New regulations proposed December 2004 requires default suppliers for small retail customers to offer at least 1 year contracts at fixed rates and obtain their power through competitive bids. These rules apply to "last resort" suppliers – those which supply power to customers who can't or don't choose to receive power through alternative suppliers. Current default rates are capped as a result of the restructuring related to the Electric Choice Law. The intent of these new regulations is to maintain service availability at reasonable terms even after the rate caps expire. Duquesne prices are open, and set by the market.		
Rhode Island	Narragansett Electric	Restructuring law passed in August 1996. Retail access phased-in beginning July 1997. 2002 legislation requires utilities to offer Standard Offer Service until January 2009.	7% reduction.
Texas	Central Power and Light, Reliant Energy, TXU Electric and Gas, TXU SESCO, Texas-New Mexico Power Company, West Texas Utilities	Restructuring law passed in June 1999. Retail access began January 2002. Transition is at least 3 years or until 40% of the power consumed within their certified service areas is provided by competitors.	Rates frozen at September 1999 levels. A bundled rate 6% less than its affiliated transmission and distribution utility rates for its residential and small commercial customers.
	See Texas update in text. *Entergy, the major provider of energy in Southeast Texas, announced in June 2004 that it has halted current efforts to move to retail open access in Southeast Texas. PUCT denied Entergy's application to create an independent organization to manage the Entergy transmission system in Texas. Entergy was also told to terminate its current pilot program and delay retail open access until a FERC approved RTO or some other independent entity certified by Texas law is in place. The company was asked to explore joining the Southwest Power Pool RTO as an alternative. Affiliated retail electric providers are required to sell electricity at the price to beat until January 2007.		

Virginia		Restructuring law passed in March 1999. Retail access began January 2002. Transition extended until 2010.	
	See section on the status of competition in the Commonwealth.		

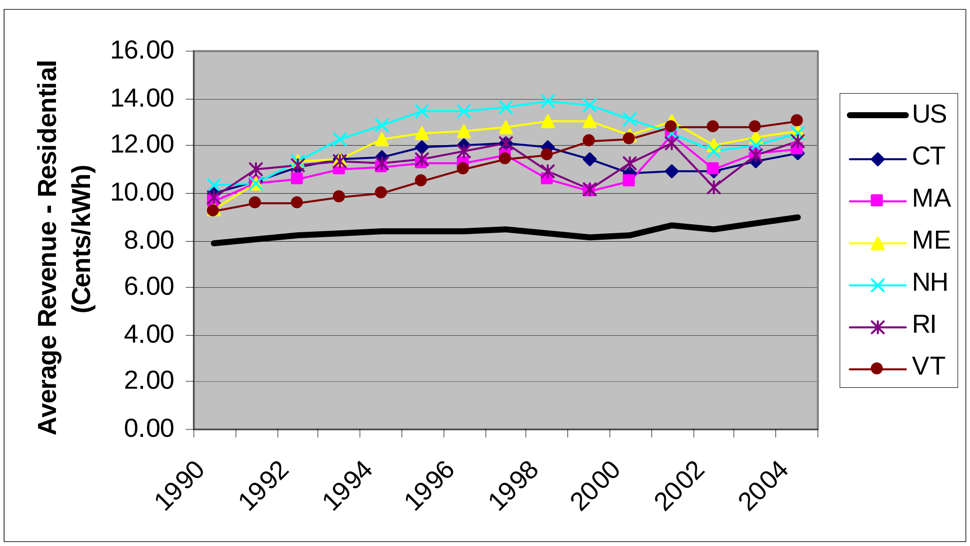
*Source: From corresponding state at
http://www.eere.energy.gov/femp/program/utility/utilityman_staterestruc.cfm
**Source: Corresponding state public utility commission

Retail Price Trends

Similar to the paper by Apt,[15] that was summarized earlier in this report, U.S. Department of Energy, Energy Information Administration[16] average revenue data (essentially, the average price for the sector) were plotted to see price trends from 1990 through 2004. The graphs below are shown by region for the residential, commercial, and industrial sectors.

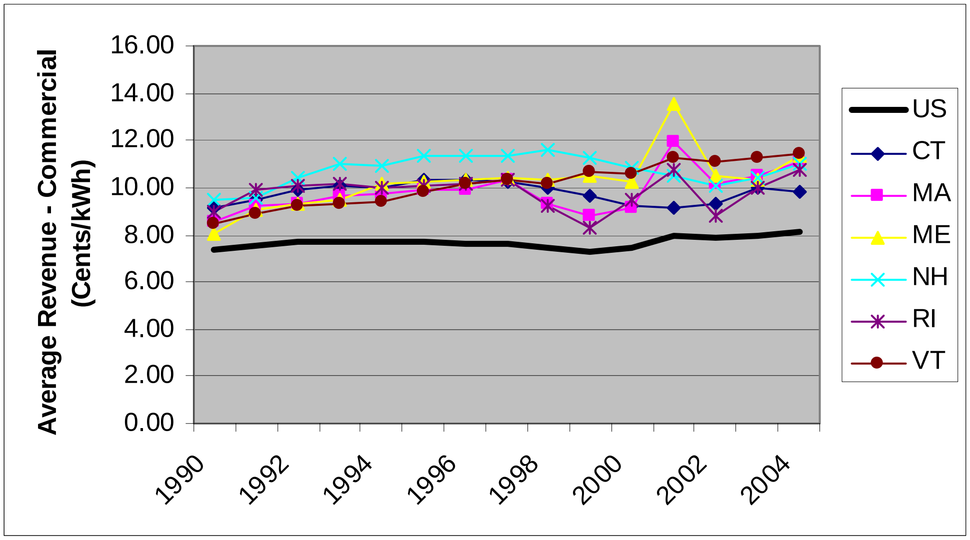
New England

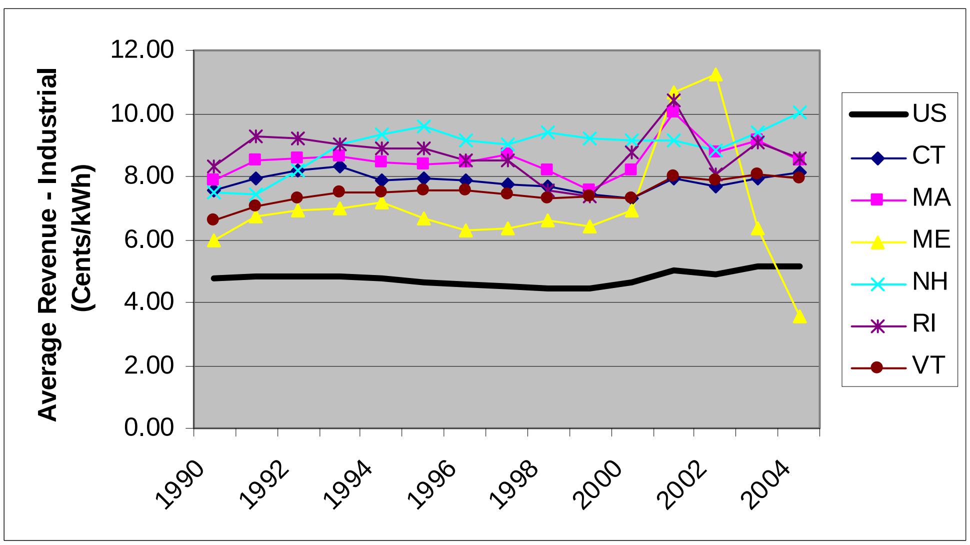
Average revenues for the New England states has exceeded the national average since 1990. The only exception to this was average revenues for service to industrial consumers in Maine in 2004. However, prices in Maine, though not shown on this graph, rebounded in 2005. The drops seen in the late 1990s in states like Massachusetts, Rhode Island, and Connecticut (and New Hampshire after 2000) residential prices can be attributed to rate reductions that came with the restructuring plans of these states. Massachusetts prices have returned to pre-discount levels. In 2001, both commercial and industrial consumers saw prices spike in all states except



[15]Jay Apt, "Competition Has Not Lowered US Industrial Electricity Prices," Carnegie Mellon Electricity Industry Center, Working Paper CEIC-05-01, 2005. The paper is available at, www.cmu.edu/electricity.
[16]DOE/EIA, Form EIA-861, "Annual Electric Power Industry Report," 2005.

for Vermont (which is the only non-restructured state in this figure). Vermont has seen its average revenues in all three sectors climb steadily from 1990 to 2004 (residential and commercial Vermont prices went from near the lowest to near the top).

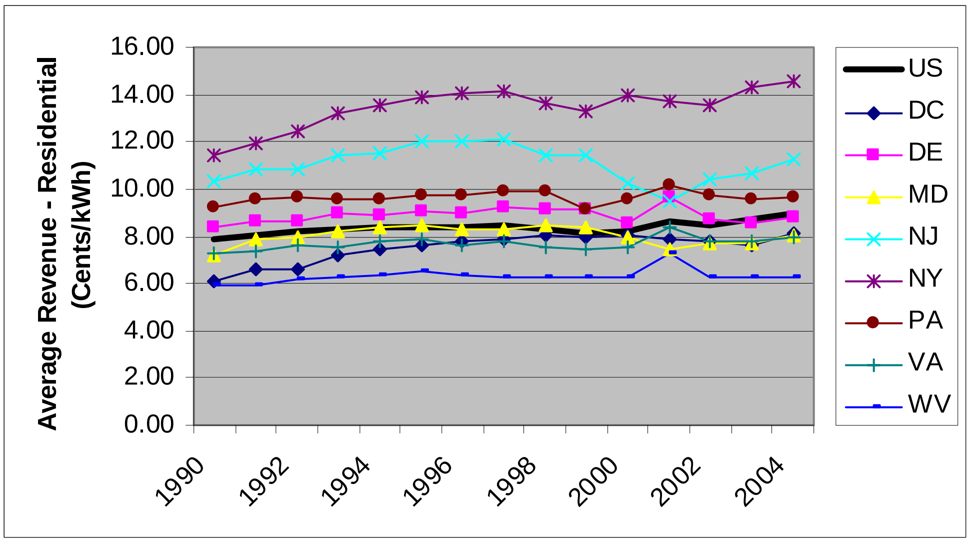


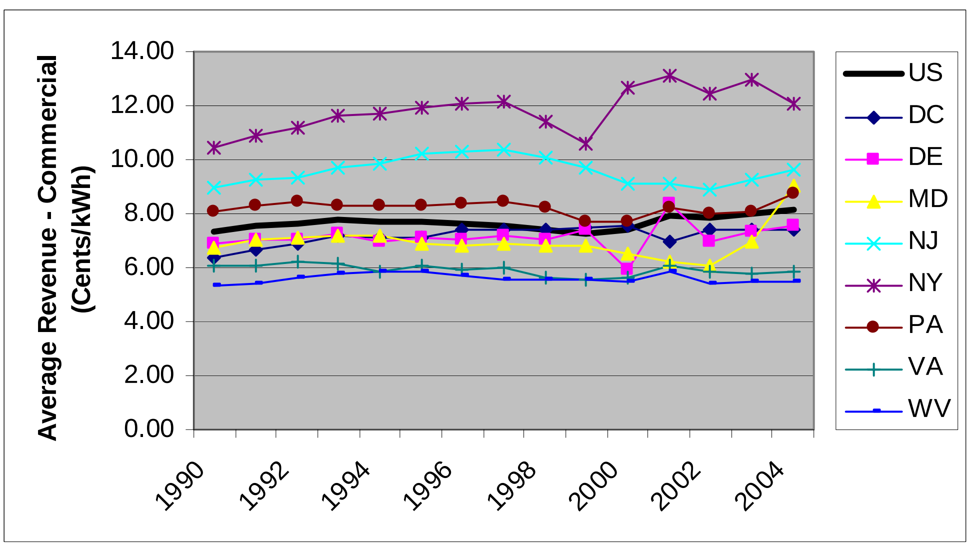


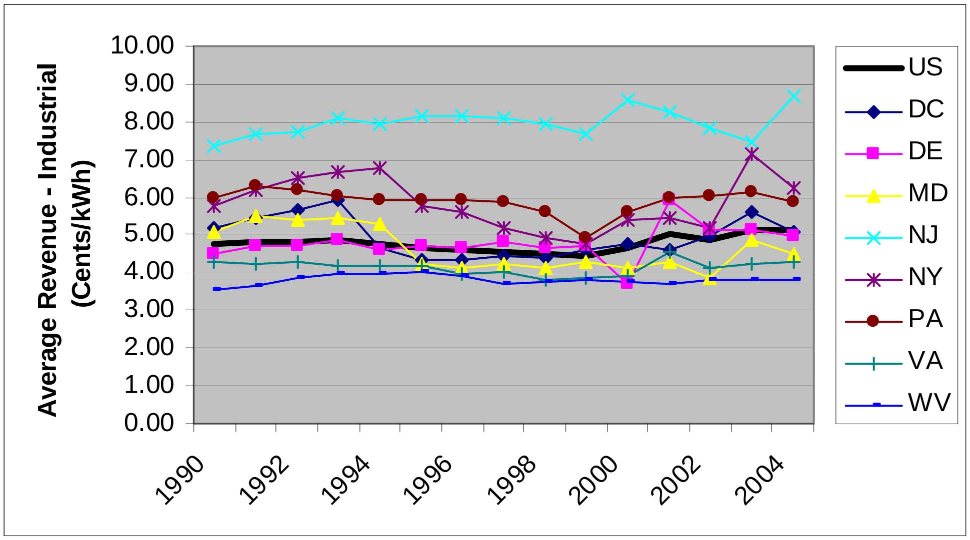
Mid Atlantic

New York and New Jersey had the highest average revenues of the three sectors. The Industrial sector is the only sector in which New York does not run the highest average revenues. Average revenues from New York industrial customers dropped from 1994 to 1999 before steady increases to 2003 where prices spiked.

Industrial average revenues in New Jersey were almost twice as high as the states in the region. Residential average revenues in New Jersey dropped in 1999 when the state opened retail competition, rolling rates back 5%. In 2000, average revenues from commercial consumers fell sharply in New York only to rebound the following year. Commercial average revenues for Maryland are on a significant upward trend since 2002. West Virginia offered the lowest in all three sectors, while Virginia stayed steadily below the national average in all sectors. Many of the states in this region stayed at or near the national average in all three sectors

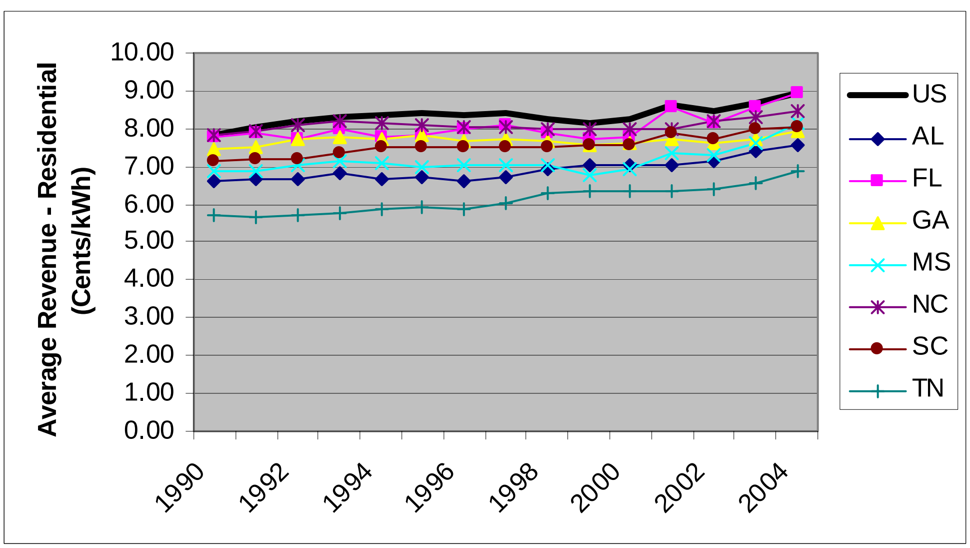


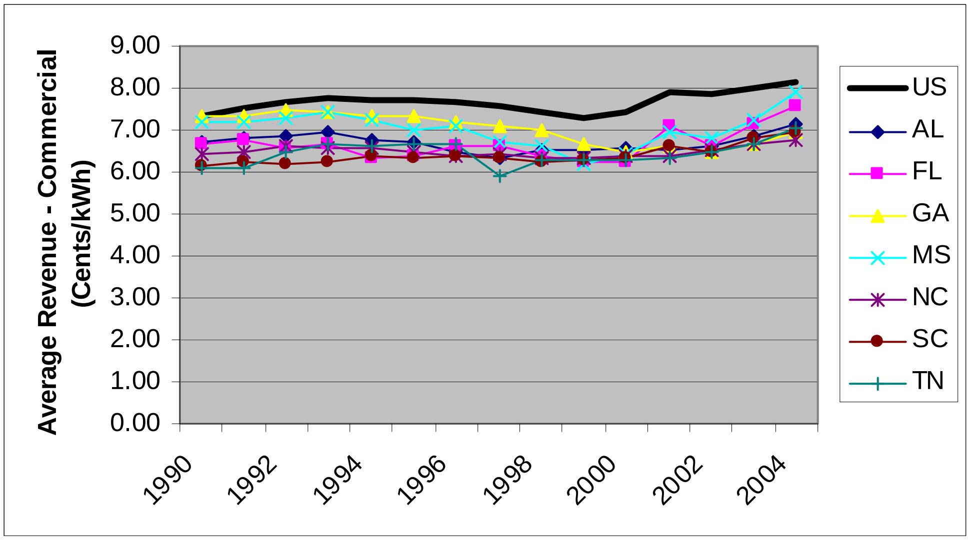


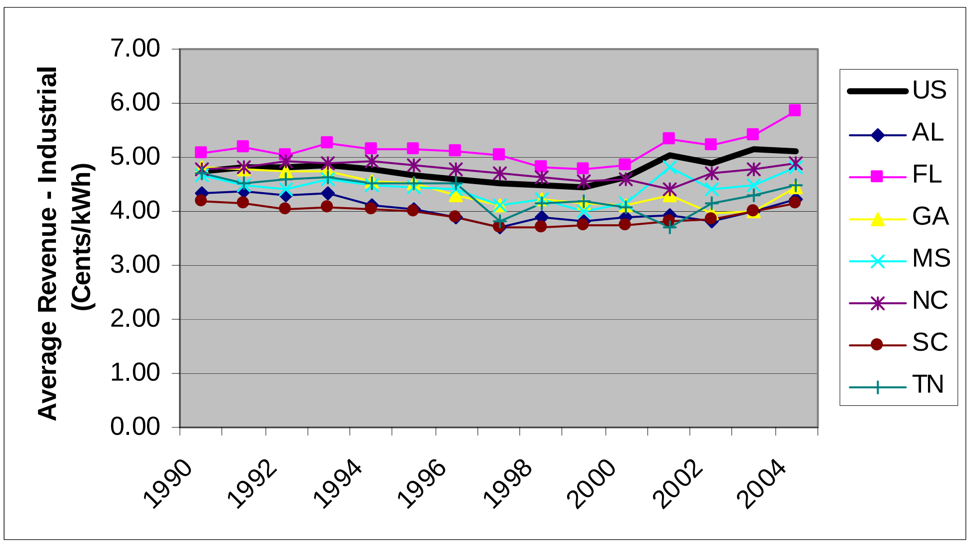


Southeast

With the exception of industrial sector average revenues in Florida, average revenues for the region stayed at or below the national average in all sectors. Average revenues appear to move in a similar path as the national average. In all three sectors, no state saw average revenues change by greater than 1.5 cents. Average revenues for the retail sector never top 9 cents (compare to New England where average revenues never went as low as 9 cents).

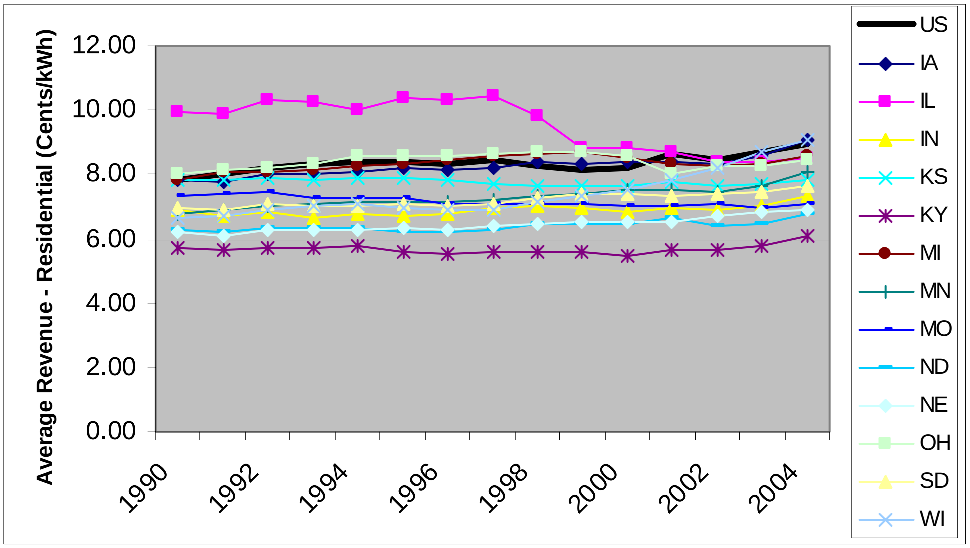


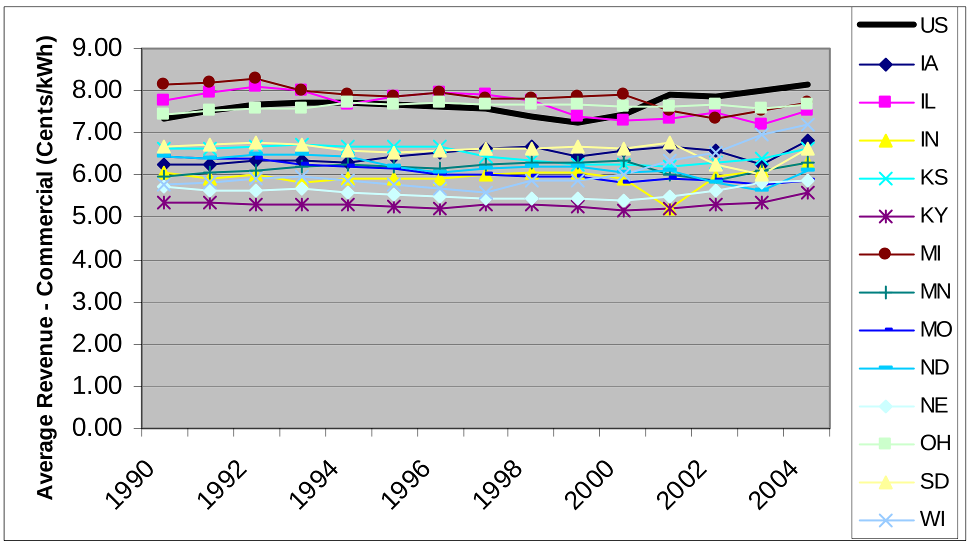


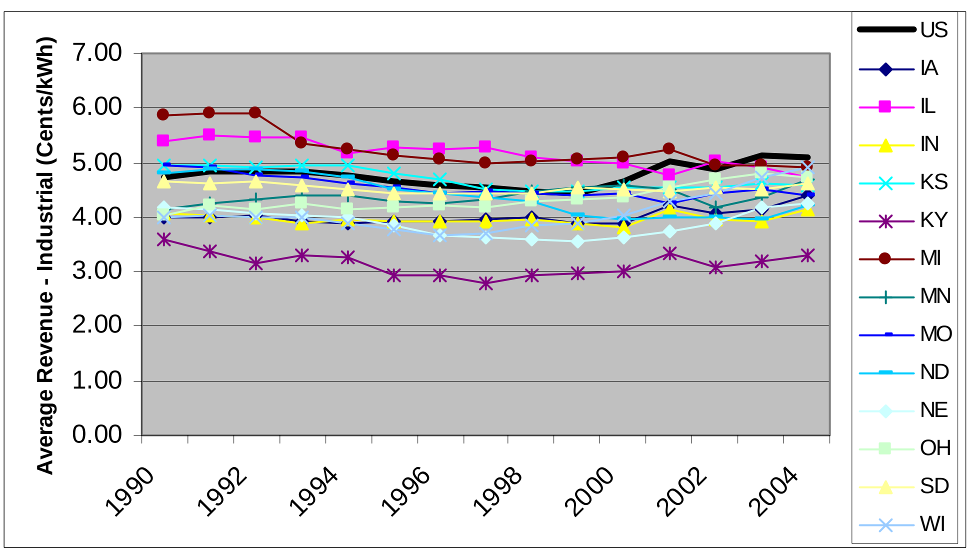


Midwest

Average revenues for this region tended to be at or below the national average. The Illinois residential sector started well above the national average, but when the state began restructuring in 1997, a 15 percent and another 5 percent roll back of rates reduced the state's average closer to the national average. All other states exhibited very little price fluctuation. The industrial sector of Missouri had prices decrease from 1990 to 2004, as did Illinois.

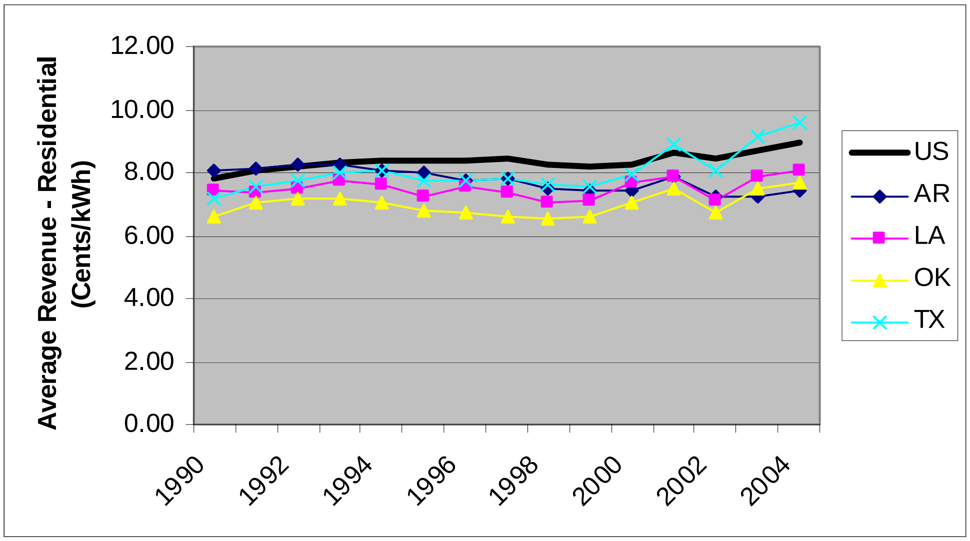

Average Revenue - Residential (Cents/kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
IA
IL
IN
KS
KY
MI
MN
MO
ND
NE
OH
SD
WI

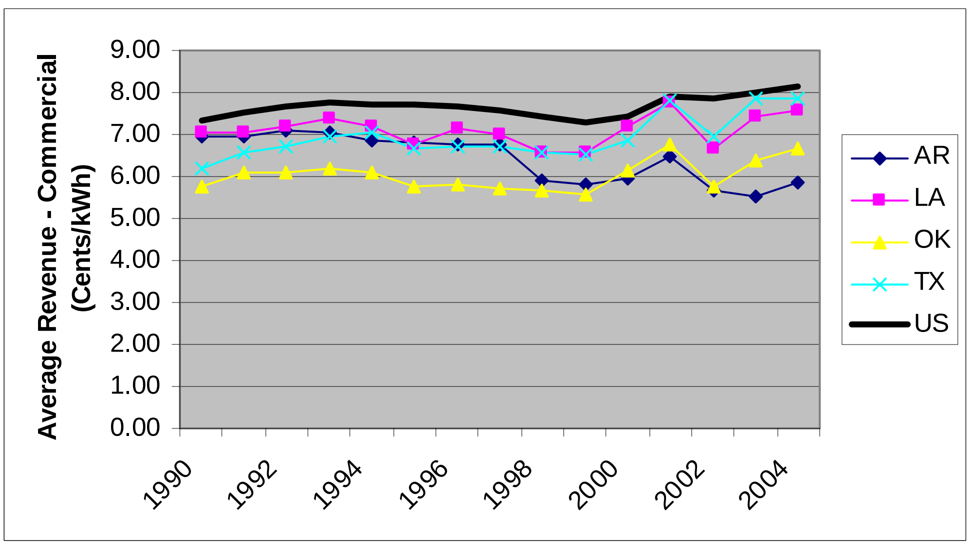

Average Revenue - Commercial (Cents/kWh)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
IA
IL
IN
KS
KY
MI
MN
MO
ND
NE
OH
SD
WI

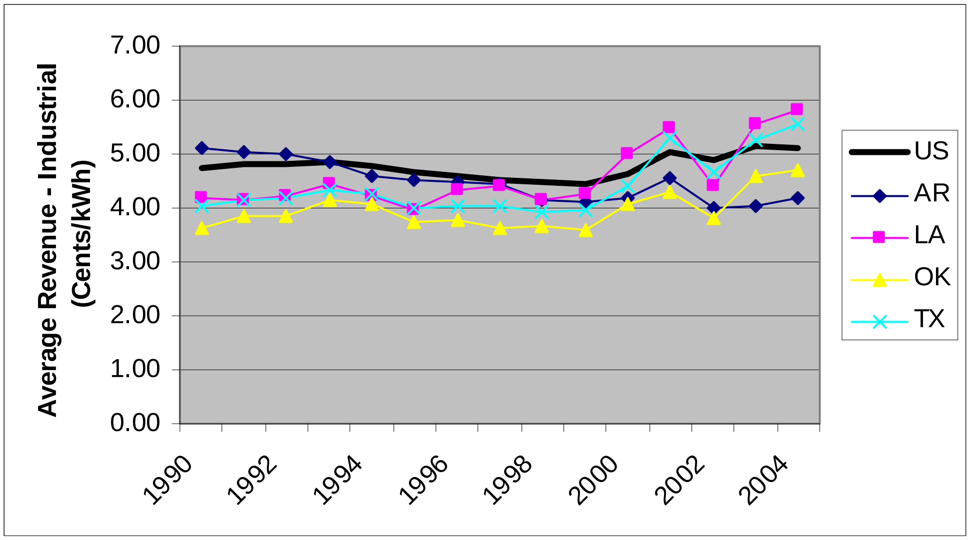

Average Revenue - Industrial (Cents/kWh)
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
IA
IL
IN
KS
KY
MI
MN
MO
ND
NE
OH
SD
WI

Middle South

Most average revenues in this region tended to stay below the national average until 2001. In 2001, average revenues in the Texas residential and industrial sectors, as well as the Louisiana industrial sector, climbed above the national average. Arkansas average revenues decreased in all sectors. Oklahoma and Louisiana average revenues tend to be correlated in each sector, though Louisiana always had higher average revenues.

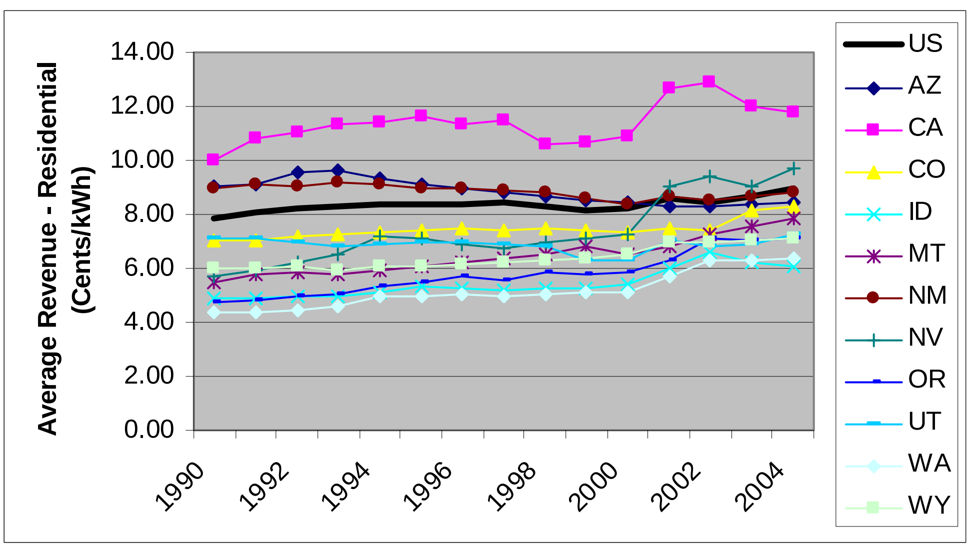


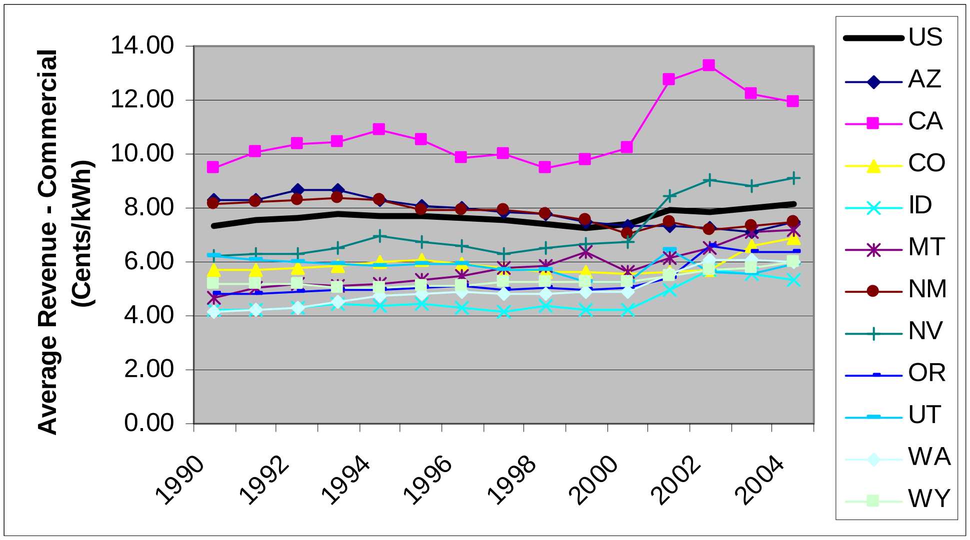


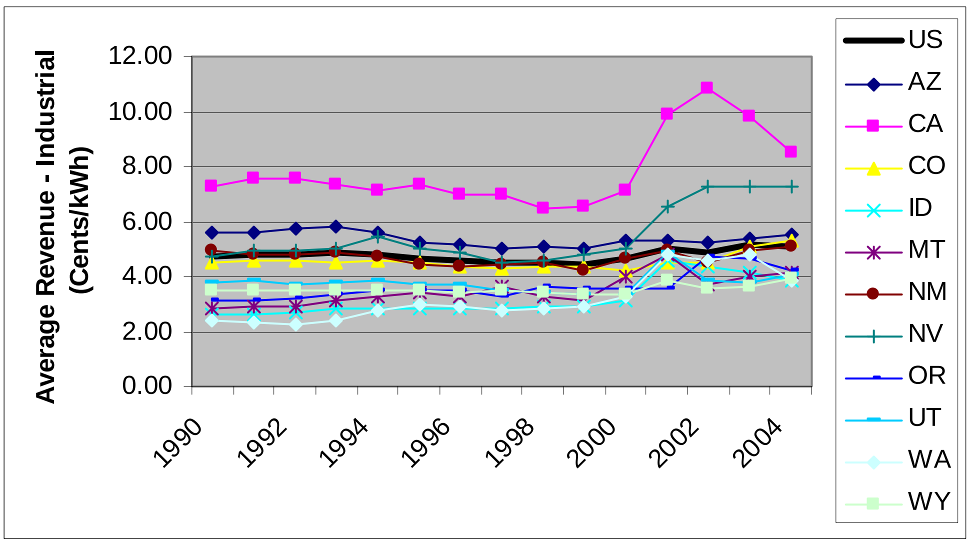


West

The most notable occurrence in the west since 1990 was the California and western power crisis. This caused average revenues in all sectors to rise dramatically in California. However, average revenues also jumped in Nevada and Washington. The average revenues of the residential sector in many states, including Oregon, Idaho, and Utah also increased, though to lesser degrees. Through all of this, the average revenues in New Mexico and Arizona decreased in the residential and commercial sectors, going from above the national average to slightly below. Average revenues in California, though down, have not returned to pre-crisis levels.




Average Revenue - Commercial (Cents/kWh)
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
AZ
CA
CO
ID
MT
NM
NV
OR
UT
WA
WY


Average Revenue - Industrial (Cents/kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
1990
1992
1994
1996
1998
2000
2002
2004
US
AZ
CA
CO
ID
MT
NM
NV
OR
UT
WA
WY

Part B

Determining Industry Competitive Structure: Perspective on Results to Date

Given the results of electric industry restructuring so far, as discussed above, it is appropriate to consider why competition has not been, at least from the customers' perspective, more robust and beneficial as was once hoped. The desire here is to generate a constructive discussion on how to address the problems identified here.

A competitive market is usually defined as a market that has many buyers and sellers, has relatively easy entry to the market by sellers, where buyers have or can readily get product information, and no buyer or seller has the ability to significantly affect the market price. Few markets fit the textbook definition of a perfectly competitive market, however. Markets vary by degree of their competitiveness. A significantly imperfect market may have problems similar to an imperfectly regulated one, such as prices significantly above competitive levels, an inefficient allocation of resources, and fewer choices for customers.

Just how competitive a particular industry is depends on three general structural characteristics: (1) the market concentration or market share of the suppliers in the industry, (2) the ease with which alternative suppliers can enter a market, and (3) the overall market demand characteristics of the product. By examining these three characteristics together, the degree of competitiveness of any industry or market can be determined. More specifically, by examining these characteristics, the amount of control or price leveraging ability firms in the industry are able to exercise can be determined. The power to raise the price above what would occur in a competitive market is the firm's or group of firms' market power. No single characteristic of the three would indicate a firm has or had significant market power. For example, a firm could have substantial market share, for example 80 percent of the market, but if entry or increased output from other firms in the market was relatively easy and if customers also had suitable alternatives to the firm's product, then a firm's actual market power potential may be very low.

In the electric supply industry, all three characteristics clearly play an important role. Markets are very concentrated for most geographic regions of the country, even for multi-state wholesale regions. Market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. Mass storage of electricity for later use during peak hours is generally impractical for many regions of the country. Also, demand for electricity is very inelastic, particularly in the short-run (less than one year) since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers.

Economic theory would predict, because markets are relatively concentrated, peak hour supply is often very inelastic, that is, the quantity supplied is not very responsive to the price, and demand is also very inelastic, supplier market power is likely to be very significant, particularly during peak hours.

Market Concentration

To determine industry concentration, the Herfindahl-Hirschman Index (HHI) is often used. The HHI is calculated as the sum of the squared market shares of the suppliers in the market. To characterize market concentration, several RTO and ISO market monitors and others use the HHI. This use is based on the U.S. Department of Justice merger guidelines ("Horizontal Merger Guidelines," U.S. Department of Justice and the Federal Trade Commission) and has also been adopted by FERC for its merger policy. As defined by the Guidelines, if the HHI is less that 1000, the market is considered unconcentrated; an HHI between 1000 and 1800, the market is moderately concentrated; and an HHI above 1800, the market is considered highly concentrated.

Another tool, also used by several market monitors and FERC, is the pivotal supplier index. This measures the percentage of load that can be met without the largest supplier. A supplier’s generation is considered pivotal when it is needed to meet the total market demand. This is calculated as the total supply capacity minus the largest supplier’s capacity, then divided by the total market demand. If the index is less than 1.00, then at least a portion of the largest supplier's capacity is needed to meet total demand and that supplier is "pivotal."

The HHI and pivotal supplier index are screening tools used to examine market concentration. They do not give a definitive answer on a wholesale market's competitiveness, but may suggest that further analyses are warranted. A detailed market analysis should consider all three characteristics to make a judgement about a market's competitiveness.

These tests may be more difficult to apply to electricity markets, since transmission access and availability may limit the market to a relatively small area during peak times, but expand to a much larger size at other times, perhaps even during the same day. Attempts to characterize the market concentration should take this changing market size into account. Because of this difficultly, these concentration measures are rarely applied in a dynamic way to account for the changing market size.

Unfortunately, due to a number of mergers during the 1990s, and with renewed recent interest in several large mergers,[17] the current industry trend is toward more concentration, not less. Economic theory would suggest this increased concentration would make markets even less competitive.

Ease of Alternative Suppliers' Entry into the Market

The easier it is for alternative suppliers to enter a market, the more difficult it is for the existing supplier or suppliers to maintain a price above a competitive level and earn economic rent through the exercise of market power. There are three primary means that alternative suppliers (that is, suppliers that are not already in the market) can enter the market. They can either build new generation capacity within the region, use the transmission system to import their own generation from outside the area, or bring in purchased power from another source. Unfortunately, building new generation capacity and expanding transmission capacity to increase import capabilities are both difficult and take time to complete. The difficulty is due to the requirements for obtaining a site and the necessary permits and licenses to build from the various federal, state,

[17]These include the Exelon Corp. and Public Service Enterprise Group merger that has received FERC approval, but still has several federal and state agencies to finalize; the MidAmerican Energy Holding Co. and Pacificorp (with is part of Scottish Power PLC's) merger; and the Duke Energy Corp. and Cinergy Corp. merger.

and local agencies, obtaining financing for the project, the long lead times for construction, securing fuel supply and access, and other constraints, such as possible strong public resistance and the market risk and uncertainty faced by new entrants.

In recent years, the electric transmission system has been required to provide two critical functions. The first is the traditional and important task of maintaining system reliability. This includes the adequacy of the system to supply the energy and demand requirements of customers at all times and the system's operating ability to withstand sudden disturbances.

However, the electrical transmission system is now required to provide a second critical function, market support. In a 2003 report, the North American Electric Reliability Council noted that "the transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience."

An analysis prepared for the Edison Electric Institute and the U.S. Department of Energy (summarized in the 2004 Performance Review) found that transmission expansion has not been keeping pace with generation capacity and load growth. The analysis normalized the NERC transmission capacity data (MW-miles/MW-demand), and found that normalized transmission capacity declined by almost 19 percent between 1992 and 2002 and is projected to decline by 11 percent for 2002 to 2012. The report also showed that normalized transmission capacity declined in all ten reliability regions between 1989 and 2002, ranging from 14 percent to 27 percent declines. The author noted that: "[o]f the 416 transmission projects planned for the next 10 years, [footnote omitted] 95% are shorter than 100 miles, with an average length of only 18 miles. These numbers suggest that most planned transmission projects are local in scope and are not intended to address large regional issues."

If this trend continues as expected, it presents a serious challenge to the development of competitive wholesale markets. While this problem is recognized and is being addressed by ISOs and RTOs, at best, it will take many years to resolve the transmission constraints and reach a point that the transmission system can provide the open access needed to support a more developed competitive wholesale market.

Market Demand

The more responsive customer demand is, the more difficult it is for suppliers to maintain a price above competitive levels. The PJM Market Monitoring Unit (MMU) in its 2004 State of the Market report noted that "[t]he ability of load to respond to changes in price is a critical component of a competitive market which remains as yet undeveloped in the wholesale electricity market" (p. 87). The total MWh of load reductions in PJM's economic demand-side response program (mostly from the real-time rate option) has increased from 50 MWh in 2001 to 48,622 MWh in 2004, for January through September 2004. To put that in perspective, PJM currently has a total annual energy delivery of approximately 700 million MWh. Obviously, the savings from these programs is only a small fraction of the total energy used in PJM.

In a survey of state customer demand-side response programs, PJM identified 7,030 MWs of load that are exposed to real-time prices through tariffs approved by the state commissions in New Jersey and Maryland. An additional 934 MWs are enrolled in independent demand-side response programs. In sum, the PJM, state, and independent demand-side response programs account for 11,562 MWs in the PJM system. Again, for perspective, the PJM peak demand is about 131,330 MWs and has approximately 163,806 MWs of generating capacity.

While the demand-side response programs are growing, they still represent a fraction of the total energy use. The PJM MMU states that:

> [t]he demand side of wholesale electricity markets is severely underdeveloped. This underdevelopment is among the basic reasons for maintaining an offer cap in PJM and in other wholesale power markets. It is widely recognized that wholesale electricity markets will work better when a significant level of potential demand-side response is available in the market. The PJM demand-side program should be understood as one part of a transition to a fully functional demand side for its Energy Market. [p. 86]

This “underdevelopment” of demand-side response programs is not what makes the quantity of electricity demanded by consumers relatively unresponsive to price changes. This unresponsiveness is mostly a function of the underlying demand for the product, which is well known to be very inelastic, especially in the short run. The demand elasticity is a measure of the degree of responsiveness that the quantity demanded changes relative to the price change. Inelastic demand means that for a given change in price, the quantity demanded changes less than proportionally. For example, if the price for electricity increased by 50 percent, but the quantity demanded decreased by only five percent, the reduction in quantity demanded would be less than a proportional decrease. The point is that it is the proportional change that is important, not just the absolute change. The reason for this inelasticity in the demand for electricity is that there are few substitutes that customers can switch to quickly. Over time, however, customers can replace air conditioners, appliances, lights, and other electrical devices with more efficient replacements. But that simply takes time.

The fact that customers cannot respond quickly to price changes gives suppliers some degree of price leverage, given also that there are both highly concentrated markets and significant entry difficulties for alternative suppliers. Again, all three structural characteristics are important in determining a firm's or group of firms' market power.

It would be advantageous to have at least one of these structural characteristics working in favor of competitive market development–and, ideally, at least two would be more beneficial to consumers. Unfortunately, for reasons just explained, the electric supply industry is characterized by highly concentrated markets, entry barriers for alternative suppliers to compete in regional markets, and very unresponsive demand. Recognizing these limitations, ISOs and RTOs must use mitigation procedures in order to attempt to prevent suppliers from taking advantage of any market power they may be able to exercise.

Capacity Credit Markets

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources equal to the peak load that it serves plus a reserve margin. LSEs are defined as entities that provide electricity to retail customers. LSEs can acquire capacity by buying or building units, by entering into bilateral arrangements with terms determined by the parties, or by participating in the capacity credit markets operated by PJM. The PJM capacity credit markets are designed to balance the supply of and demand for capacity not met through the bilateral market or through self-supply. The capacity credit market participants would include competitive LSEs that need to acquire the capacity resources required to meet their capacity obligations or to sell capacity resources no longer needed to serve load.

In its assessment of the capacity markets, the PJM MMU concludes:

> [g]iven the basic features of market structure in both the PJM and ComEd Capacity Markets, including high levels of concentration, the relatively small number of nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the likelihood of the exercise of market power is high. These structural conditions are more severe in the ComEd Capacity Market than in the PJM Capacity Market. Market power is endemic to the structure of PJM Capacity Markets. [p. 33]

Structural Issues in the Development of Competitive Electricity Markets

Whether retail customers will see benefits, for example, lower prices and a greater increase in supply and demand options than under cost-based regulation, depends on three structural problems that the industry currently faces.

Market Power

Prices should reflect marginal cost, without significant mark-up, if there is no or only minimal market power, as discussed above. Since markets are highly concentrated, alternative suppliers have limited ability to enter the market and compete with incumbent suppliers and because demand is very inelastic, the possibility of market power being exercised by suppliers is a distinct possibility. The California and western power crisis of 2000 and 2001 had several causes, but supplier market power clearly played a substantial role.

Transmission System Costs

It has generally been assumed that increased generation operating cost efficiencies that may be achieved through competitive pressures and economies of scale in transmission operation would more than offset the costs of operating an ISO or

RTO and other costs incurred to maintain system reliability and integrity. However, the cost of developing and maintaining and the current ISOs and RTOs has increased considerably over time, as noted at the beginning of this report. More than likely, the net increased cost of moving from vertically integrated utilities to an ISO/RTO arrangement will be passed on to retail customers. When the vertical structure of the former utilities ended, responsibility for the functions that were performed by the utility transferred to the ISO or RTO. Whether this new industry arrangement is a net gain or loss is not known at this time, since it is still forming. The extensive blackout of August 2003, while perhaps not caused directly by the restructuring of the industry, does suggest that attention needs to be given to all the functions that the vertical utilities used to perform and the new incentives and responsibilities that competitive suppliers and transmission owners now face.

Price-Setting on the Vertical Segment of the Supply Curve

A third structural problem is the frequency with which the vertical portion of the regional supply curve determines the regional price. These are the peak hours when the demand for electricity increases to a point where the highest priced generation units are needed to operate to meet the demand.[18] Some states (described earlier in this report) are now depending on the wholesale market to secure supply for retail customers and to determine the price for power. In this market, for those hours, the price for power is set by the high cost marginal generation units, typically units that use natural gas. The prices that the consumers in these states are paying exemplify this point – they are no longer paying the *average cost* of power produced by their utilities, but are paying the *marginal cost* of power in the region. Ideally, in an efficient competitive market, this is what is needed to send the correct economic signal to consumers and suppliers to use and supply power efficiently. However, as noted, the power industry is not like most competitive markets. This industry has a long flat supply region that extends over a wide output range, and then turns upward and becomes

[18]This summer is providing a good example of this occurrence, where the price for power has been above $100 frequently on the hot days and occasionally much higher.

nearly vertical as the maximum output is approached. It is that vertical segment of the supply curve that is determining the price at many hours of the year.

The MMU's 2004 State of the Market Report, states that combustion turbine (CT) generation was the marginal unit 22 percent of the time during 2004. This does not include gas-fired combined-cycle generation, which would include most new units added to PJM in recent years and other marginal steam generation units. Even so, this is still nearly 2,000 hours in the year when CT is determining the price and will have an impact the overall wholesale price and eventually, retail customers.

This third structural problem can be addressed through increased generation and transmission capacity and demand response programs (which would help alleviate the first problem too, market power). However, this will take time to develop, and it remains to be seen whether the current incentives will encourage sufficient building of base load capacity. So far, at least, it appears that competitive markets alone do not encourage the building of base load capacity. Suppliers appear to be unwilling to build base load capacity that will have the effect of lowering the price they receive for power. Adding base load units has the effect of lengthening the flat part of the supply curve and reducing the number of hours the upward sloping or vertical segment is determining the price. Given the investment that base load units require, and the impact they would have on the market price, it is not surprising that there is a preference for smaller intermediate and peak-load generation units.

Transmission owners that also own generation are also less likely to be willing to build or upgrade transmission facilities that will only serve to lower the price received for the power sold from the generation facility. Under cost-based regulation, the incentive was to perhaps overbuild capacity since it would contribute to the company’s earnings. These incentive issues were dealt with, however clumsily, under cost-based regulation for many years using used-and-useful and prudence standards. However, the incentives in the type of markets developing now are poorly understood and only partially dealt with in the current policy discussions in the industry.

The conventional view is that frequently higher prices (that is, “scarcity” prices) will induce more building of capacity. While it is true that there was a building boom that lasted roughly from about 2000 through 2003, nearly all that capacity was natural gas-fired, and new building activity has dropped off considerably. (This decline in the building of new capacity and the impact that natural gas prices now has on power prices are discussed in last year's Performance Review, pages I-6 through I-9.)

Electric Supply Industry Market Structure: Competitive, Monopoly, or Oligopoly?

In addition to the three structural characteristics of electricity supply and demand described above, there are other features of electricity and market design that may also contribute to suppliers' ability to exercise market power. First, electricity is, by design, homogenous, that is, a kilowatt of power that is delivered on the transmission and distribution system must conform to the standards of the interconnection requirements that all suppliers must follow to be connected to the electric system.[19] From an economic standpoint, that means that it is difficult for a supplier to differentiate its product or for customers to distinguish one product from another. Most customers appear to be indifferent to the type of resources used to generate the power they consume.[20] In general, consumers cannot distinguish one company's kilowatt hours from another. While this makes it easier for customers to evaluate the offers from suppliers, it also makes it difficult for alternative suppliers to separate themselves in the market, for example, by saying they offer more reliable power (customers are typically explicitly told that reliability will not be affected by the choice of supplier they make). As a result, price is the main criteria customers have to evaluate offers they receive. Overall, this is an advantage for incumbent retail suppliers since it usually means that customers are reluctant to switch suppliers unless they see a appreciably lower price

[19]In the electric supply industry, this generally means meeting or exceeding standards for "Good Utility Practice." See for example PJM's Operating Agreement.

[20]For electricity, one important exception is "green" power, that is, power that is produced in part or completely from renewable resources. Some retail customers, when offered the option, choose to pay a higher price to purchase green power rather than that what is offered from conventional fuel sources.

being offered by an alternative supplier.[21] This has been especially true for residential customers.

Since electricity is not economically storable in large quantities, it must be generated when demanded and is consumed nearly instantaneously. Consumers or others acting on their behalf, cannot simply put a large amount of power in storage when the price is low for use later or resell it when the price is higher. If storage were available, it could be used to moderate the price and dampen any supplier market power. Also, because of transmission constraints and other physical limits on sending power over long geographic distances, power may not be available to send to higher priced areas to moderate the price.

Finally, suppliers operating in the RTOs and ISOs have considerable knowledge of rival firms' cost structures. This information can be acquired from public information sources, the supplier's own knowledge of costs, and the fuel type and vintage of generation resources owned by rivals. In addition, suppliers repeatedly interact on an hourly and daily basis in the market. This allows suppliers to gather information on rivals and how they respond in different market conditions. They may not know specifically which supplier bid and at what price, but suppliers can see the price results and the results of their own bidding under various market conditions.

In addition to valuable information gathering, the repeated interaction by the firms can lead to collusive behavior, where they attempt to cooperate with each other in order to raise the price, as seen in California during the 2000-2001 power crisis. The repeated interaction also makes it easier to enforce an agreement to control prices. While direct cooperation and collusion would violate anti-trust laws, "tacit collusion" could form with close interaction that reinforces the mutually beneficial action that will lead to higher profits for all suppliers. For example, an agreement (or even an understanding) to reduce output during peak hours would drive up the price for all

[21]Customers are likely considering transaction costs from switching, including search costs and weighing the perceived risk of switching to an alternative supplier. Put simply, it is not worth the "hassle" of attempting to find and switch to an alternative unless there is believed to be a clear benefit to make it worth the time, money, and effort required to make a good choice.

market participants.[22] Such agreements (such as cartels) are often difficult to enforce when individual actions cannot be easily monitored and enforcement and retaliation for "cheating" is also difficult. With repeated daily interaction, however, monitoring and enforcement is possible.

Of course, this type of behavior is anti-competitive and completely contrary to the policy goals that were intended when the RTO and ISO structures were being formed. However inadvertently, the federal sanction and approved rules could be what allows enforcement and monitoring of an agreement. The openness of the market that is needed for price transparency for buyers and sellers in the market may have an unintended side effect[23] of allowing price "signaling" for suppliers. The characteristic of concentrated electricity markets and that often a relatively small number of suppliers are operating in an area, increases the potential for collusive behavior.

The higher profit from firms' exercising market power should attract other firms and drive down the price. But due to the entry difficulties, this will take time and even be discouraged by the existing suppliers not allowing the price to exceed an entry point for new suppliers to profitably enter the market. Potential entrants, knowing that there could be a price drop if they do enter, may decide not to enter or expand in a market even when the current conditions are favorable. Even if no reaction from incumbent suppliers is anticipated, the additional supply capacity itself from the new entrant may reduce the price below a profitable point. This may be especially true for potential expansion of base load capacity.

[22]Availability of a single "swing producer" would make an agreement easier, that is, a single generation owner that represents a large share of the market, where there is limited generation and transmission availability from the outside that could enter the area. Other generators would benefits from the dominate firm's actions without reducing output (or economically withholding) themselves.

[23]Unintended on the part of policy makers, who are understandably concerned about providing price transparency. Suppliers, on the hand, may easily see the advantages of transparency.

All these characteristics and features taken together[24] suggest that the market structure that is emerging is certainly not perfectly competitive, an impossible standard for any market to reach, nor could the structure be characterized as a pure monopoly, that is, one supplier – although that may occur in some local areas or subregions of an RTO or ISO where one supplier generates nearly all the power and transmission constraints limit outside supply options. Rather, the structure that is suggested is one of an oligopoly, defined as a market where there are a few firms supplying all or most of the output. There are a number of specific oligopoly models that are used to examine industry structure. These models are complex and usually are expressed in mathematical form.[25]

As a practical matter, the question becomes, are customers better off under the developing oligopoly structure or under the previous regulated monopolies structure? Both structures are economically inefficient and not ideal and both lead to consumer prices above marginal cost. One way to do the comparison would be to, on one side of the equation, consider the inefficiencies under regulation, including over capitalization costs, operational inefficiencies, regulatory compliance costs, and resource allocation inefficiencies. Then on the one side of the equation, compare this to the inefficiencies of oligopoly or market power, the higher cost from the loss of vertical economies, the RTO or ISO formation and operation costs, the higher cost of capital for investment in a competitive market, possible under capitalization costs (from increased reliance on intermediate and peak capacity rather than base load capacity), and any additional

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[24]These include, as discussed, a relatively small number of suppliers in a region or subregion, significant barriers to entry for other suppliers, inelastic market demand, a homogenous product, supplier knowledge of rival firms' cost structure, repeated hourly and daily interaction by the firms in the market.

[25]Some example of where models have been applied to the electric supply industry are Benjamin F. Hobbs and Fieke A. M. Rijkers, Strategic Generation With Conjectured Transmission Price Responses in a Mixed Transmission Pricing System – Part I: Formulation," IEEE Transactions On Power Systems, Vol. 19, No. 2, May 2004 and Yan Sun and Thomas J. Overbye, "Market Power Potential Examination for Electricity Markets Using Perturbation Analysis in Linear Programming OPF Context," Proceedings of the 38th Hawaii International Conference on System Sciences - 2005, 0-7695-2268-8/05, IEEE, 2005.

distribution or transmission costs (balanced against any greater scale economies in transmission from a large regional system).

Needless to say, this would require a massive effort to account for all these factors and would require a great deal of judgement to place a valuation on each of these factors. In effect, however, there is an experiment going on right now in the U.S., where parts of the country are developing RTOs and ISOs and others are not, and some states have retail access and others do not.

Wholesale Price Mitigation

Many ISOs and RTOs have an overall price cap or upper price limit, for example, $1,000 per MWh limit on the prices offered. Some also use triggers or thresholds that limit the amount prices can change in a given period of time. For example, the New York ISO uses a reference value, where if a bid is above the reference value by $100 per MWh or is 300 percent greater and the bid causes the price to rise by $100 per MWh or increase by 200 percent, then the bid is replaced with the reference value. PJM uses offer price caps in local areas that are judged to be "structurally noncompetitive." In these cases, the offers would set the price above competitive levels, without price mitigation. The capped units receive the higher of the market price or their offer price cap. The offer price cap is calculated based on the incremental operating cost of the generation resource, plus ten percent.

The PJM rules designed to limit market power that could be exercised include the $1,000 per MWh offer cap in the PJM energy market and offer capping of units owned by those that have the ability to exercise local market power. The PJM MMU notes that "[n]o evidence suggests that market power was exercised in these areas during 2004, primarily because of generation owners' obligations to serve load and PJM rules limiting the exercise of local market power. If those obligations were to change, however, the market power-related incentives would change as a result."[26]

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[26]PJM MMU, 2004 State of the Market Report, p. 53. Another analysis that notes the importance of the load obligations in curbing market power is James Bushnell, Erin T. Mansur, and Celeste Saravia, "Market Structure and Competition: A Cross-Market Analysis of U.S. Electricity Deregulation," March 2004.

PJM MMU states that PJM "rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation."[27]

PJM and other RTOs and ISOs also try to limit market power through market design and structural changes. Where and when market power exists, the rules to limit market power are designed to mitigate it. The structure and design changes are intended to limit the ability to exercise market power over time. The MMU states, "[m]arket design itself is the primary means of achieving and promoting competitive outcomes in the PJM Markets. One of the MMU's primary goals is to identify actual or potential market design flaws. PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power."[28]

PJM defines the "offer price cap" as "[t]he weighted average Locational Marginal Price at the generation bus"[29] or "[t]he incremental operating cost of the generation resources as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus 10% of such costs" or "[f]or a unit that is offer capped for 80 percent or more of its run hours, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the higher of $40 per megawatt-hour or the unit-specific going forward costs of the affected unit" or "[a]n amount determined by agreement between the Office of the Interconnection and the Market Seller."[30]

When applied on a cost basis, the offer cap is based on the "incremental operating cost of the generation resource as determined in accordance with Schedule 2

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[27]PJM MMU, 2004 State of the Market Report, 63.

[28]PJM MMU, 2004 State of the Market Report, p. 45, footnote omitted.

[29]Sheet No. 131A, PJM Operating Agreement.

[30]Sheet No. 132, PJM Operating Agreement.

of the Operating Agreement and the PJM Manuals, plus 10% of such costs."[31] The components of the Schedule 2,[32] appear to be reasonable, but have an "other incremental operating cost" component. In addition, the cost components are self-reported. This may cause an expansive definition of incremental cost and could create a "moral hazard" problem in reporting. It is not clear what analysis, if any, has been done to verify or audit the calculation of incremental cost that is reported by an independent verification of these costs. Under current PJM rules, units are also exempted from being offer capped based on when they were constructed and unit location.[33]

The MMU also calculates a "price-cost markup index"[34] that is intended to "estimate the difference between the observed market price and the competitive market price."[35] The markup index estimates the percentage of the price that is markup above marginal cost. The average markup index in 2004 was 3.4 percent, with a maximum of six percent and minimum of zero. Since the markup is based on the marginal cost estimate that includes the 10 percent adder, mentioned above, the MMU also calculates an adjusted markup index that takes out the 10 percent adder. The average adjusted index was 8.4 percent (that is, 8.4 percent of the price is markup above the adjusted marginal cost), with a maximum of 12.3 percent and minimum of 4.7 percent. Both the unadjusted and adjusted indices are relatively modest. However, it assumes that the marginal cost estimates are accurate (which, as noted, may be overstated) and averages the markup values over many units at various times and locations. This method of calculation could understate that actual markup considerably.

[31]Operating Agreement, 6.4.2 (a) (ii), Sheet No. 132.

[32]"Components of Cost," PJM Operating Agreement, Sheet No. 167.

[33]PJM Operating Agreement, section 6.5, "Exempt Generation Resources."

[34]MMU, 2004 State of the Market Report, at page 67 through 69. Past years' markup calculations by the PJM MMU have been reported in pervious Market Performance Reviews.

[35]MMU, at page 67.

Offer capping is not used very often in PJM. According to PJM's MMU, in 2004, only 1.3 percent of total run hours were offer-capped in PJM. The offer-capped hours per MW has decreased since 2001 because fewer areas are deemed to be "structurally noncompetitive." Also, since the rules allow the capped units to receive the higher of the market price or their offer price cap and the cap is calculated based on the incremental operating cost of the generation resource–plus ten percent, little protection for the consumer may actually be provided. The MMU notes that

> offer capping does not result in financial harm to the affected units. Detailed analysis of actual net revenues for 2003 showed that frequently offer-capped units received net revenues that were close to those received by units not offer-capped or that were offer-capped, but for significantly fewer hours. In fact, offer capping can, at times, result in higher revenues for offer-capped units than for other comparable units because the offer-capped units operate when market conditions result in comparable units not operating.

The test is not whether "financial harm" is being caused, but whether the market mitigation measures actually limit all opportunities for suppliers to exercise significant market power. It appears that has not been properly studied in PJM.

A Closing Perspective: What We Have Learned So Far

Most observers of electric industry restructuring would agree that it has been more difficult and more complex than believed when the process began in the 1990s.[36] Because of the technical nature of electric supply and the many functions that remain regulated, the task was likely to be difficult. Difficulty and complexity are not problems in themselves, but it could lead to unintended consequences that designers could not

[36]"The" beginning would be hard to pinpoint exactly since PURPA power generation and wholesale competition began to become significant in the 1980s. However, a reasonable beginning of the current restructuring efforts could, on the wholesale side, be said to start with passage of the Energy Policy Act of 1992 and, on the retail side, with states beginning to pass legislation to allow retail access in 1996.

have anticipated. No one designed the current RTO structure, it evolved through a series of FERC orders, responses by the RTO's themselves, and the clash of interest groups in the FERC proceedings. Of course, where the industry began was also very influential, that is, the generation, distribution, and transmission infrastructure that was built over decades and the industry-specific events that preceded restructuring.[37]

Two significant recent events have occurred that will likely have a material impact on the development of wholesale markets across the country. First, FERC approved the Exelon merger with PSEG, without a hearing.[38] In the Order approving the merger, FERC states that,

> We are not convinced by arguments that Applicants should have analyzed the merger's effect on their ability and incentive to harm competition by engaging in strategic bidding (which is a form of unilateral market power). The Commission's analysis focuses on a merger's effect on competitive conditions in the market. That is, we look at the merger's effect on the concentration of the relevant markets, as measured by the HHI. Protestors argue that the HHI solely looks for the possibility of the coordinated exercise of market power and misses the possibility of the unilateral exercise of market power. They say that Applicants have not shown that the merger will not increase the likelihood of the merged firm exercising unilateral market power. We reject this argument for two reasons. First, the Merger Guidelines recognize that the HHI does, in fact, convey information about the likelihood of the unilateral exercise of market power. [Footnote 94 is: Section 2.0 of the Merger Guidelines.] Second, in order to address the screen failures in various season/load conditions, Applicants have proposed divesting units with a range of operational and cost characteristics, including the types of units that protestors argue could be used to engage in strategic bidding or withholding in order to exercise unilateral market power. Furthermore, such strategic bidding or withholding could

[37]This list would be long indeed, including the 1965 northeast blackout and its affect of industry reliability standards, the energy crisis of the 1970s that led to the passage of PURPA, the Three Mile Island accident and the nuclear power plant cost over runs, to name a few.

[38]Federal Energy Regulatory Commission, Docket No. EC05-43-000, issued July 1, 2005.

> qualify as market manipulation under the Market Behavioral Rule #2 [footnote 95 is: Market Behavior Rules, 105 FERC ¶ 61,218 (2003) Order on Reh'g, 107 FERC ¶ 61,175 (2004) Rule # 2.E "bidding the output of or misrepresenting the operational capabilities of generation facilities in a manner which raises market prices by withholding available supply from the market."] and result in, among other things, revocation of market-based rate authority.[39]

On FERC's first point, they correctly characterize the point of the section on the significance of market concentration, but missed a very important caveat clearly stated in the Merger Guidelines' section they cite. The Merger Guidelines state in Section 2.0,

> Other things being equal, market concentration affects the likelihood that one firm, or a small group of firms, could successfully exercise market power. The smaller the percentage of total supply that a firm controls, the more severely it must restrict its own output in order to produce a given price increase, and the less likely it is that an output restriction will be profitable. If collective action is necessary for the exercise of market power, as the number of firms necessary to control a given percentage of total supply decreases, the difficulties and costs of reaching and enforcing an understanding with respect to the control of that supply might be reduced. *However, market share and concentration data provide only the starting point for analyzing the competitive impact of a merger.* Before determining whether to challenge a merger, the Agency also will assess the other market factors that pertain to competitive effects, as well as entry, efficiencies and failure [emphasis added].[40]

As noted earlier, market concentration is important in determining the ability of a firm to exercise market power, but it is a screening tool that does not provide a definitive test for market power. Further analysis is needed if the concentration levels are high. Market concentration measures are not a substitute for the further analysis. As an example of the type of analysis that FERC and states should conduct is in the very next

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[39]FERC, Docket No. EC05-43-000, pp. 44 and 45 (footnotes included).

[40]U.S. Department of Justice and the Federal Trade Commission, "Horizontal Merger Guidelines," Section 2.0, issued April 2, 1992, revised April 8, 1997, p. 18.

section of the DOJ Merger Guidelines, “Lessening of Competition Through Coordinated Interaction,” where it states,

> A merger may diminish competition by enabling the firms selling in the relevant market more likely, more successfully, or more completely to engage in coordinated interaction that harms consumers. Coordinated interaction is comprised of actions by a group of firms that are profitable for each of them only as a result of the accommodating reactions of the others. This behavior includes tacit or express collusion, and may or may not be lawful in and of itself.[41]

As noted also, coordinated interaction and collusion could have particular relevance for electricity markets, given the nearly continuous interaction that firms have in RTO and ISO markets. A merger of firms of any size within the same RTO means fewer firms in the market and makes coordination more possible. In its analysis of the Exelon/PSEG merger, FERC did not examine the possibility of collusion of any sort. Also, the ISO and RTO market monitors do not examine this possibility either.

On FERC’s second response to protestors (from the above quote) that argued that there could be strategic bidding or withholding to exercise unilateral market power, FERC notes that such strategic bidding or withholding *could* (their word) qualify as market manipulation under the Market Behavioral Rule #2 (“bidding the output of or misrepresenting the operational capabilities of generation facilities in a manner which raises market prices by withholding available supply from the market”) and would result in revocation of market-based rate authority, among other things. This depends, of course, on FERC’s ability to detect such activity, which would be difficult given the considerable amount of data to examine. FERC has its own market monitor, the Office of Market Oversight and Investigations (OMOI), but it tends to focus on descriptive analysis and covers the entire country and other energy markets as well. They do not produce detailed analyses of the markets for the public to examine.[42] FERC would have

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[41]“Horizontal Merger Guidelines,” Section 2.1, p. 18.

[42]The OMOI does investigate specific market events. Two example are the Office’s analysis of the Western power crisis and the New England January 2004 “Cold Snap.” However, these are after-the-fact reviews of past events and are mostly

to conduct the investigation or have a means to detect possible collusive actions.[43] FERC does not even appear to be currently aware of the possibility.

Clearly, strategic bidding and withholding are issues that need to be examined. As noted, there are academic papers that suggest that strategic bidding could happen and how it could (and perhaps actually does) happen in LMP markets.[44] While academics have been studying this issue for a few years, it is not purely an academic exercise. There have been various seminars on how to bid in LMP markets, with titles such as, “Formulating Bidding Strategies for GENCO Assets in LMP Markets” and another with the title “Using Shadow Settlement as a Strategic Tool To Improve Bottomline Profits in LMP Markets.” The first seminar promises attendees are that they will learn the answer the question “How can you formulate bidding strategies that maximize your expected profits from both the day-ahead and real-time markets?” Another seminar objective is (and perhaps more worrying) “How should you formulate bidding strategies to reflect market mitigation rules?” The second seminar has as an objective to show attendees “How can you use shadow settlement as a strategic tool to provide feedback to traders on bidding strategies?”

Of course, it should be expected that generation owners should learn the ISO and RTO rules and seek to make a profit in the process. That is the point of having a competitive market, that is, using the profit motive to drive cost-minimizing and profit-

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descriptive in nature. This is helpful to understanding the event, but not a substitute for more detailed analysis of the event or for analysis of the markets in general.

[43]FERC’s state of the markets report notes that in February 2005 two Texas retail providers have sued several electricity suppliers alleging price fixing and collusion. Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, “2004 State of the Markets Report,” June 2005, p. 131.

[44]Some example, that have further citations, are Benjamin F. Hobbs and Fieke A. M. Rijkers, Strategic Generation With Conjectured Transmission Price Responses in a Mixed Transmission Pricing System – Part I: Formulation,” IEEE Transactions On Power Systems, Vol. 19, No. 2, May 2004 and Yan Sun and Thomas J. Overbye, “Market Power Potential Examination for Electricity Markets Using Perturbation Analysis in Linear Programming OPF Context,” Proceedings of the 38th Hawaii International Conference on System Sciences - 2005, 0-7695-2268-8/05, IEEE, 2005. These papers were both provided as part of the response to first set of ComEd Data Request.

maximizing behavior that leads, hopefully, to a competitive market outcome. From a public policy standpoint, however, it is important to ensure that it really is a competitive outcome, and not something that has the appearance of a market, that is, with buyers and sellers and high volume, but where suppliers are earning economic profit and imposing additional costs on society. Besides studies of California during the 2000-2001 crisis period, no analysis has been done that studies actual bidding behavior in an ISO or RTO market. However, the academic discussion and what bidders could or may be able to do in these markets, suggests that, at the very least, the issue of strategic bidding needs to be studied. As another academic paper warns, "[g]iven the cost of mistakes, e.g., the California electricity market in 2000, a more than incremental change in a market design requires careful analysis, especially of how the participants can outwit the designers."[45]

The second significant recent event that will likely have a considerable impact on the development of wholesale markets is the passage of the Energy Policy Act of 2005. While the legislation is far reaching and is covers many areas of energy policy, of particular interest in the context of electric market competitiveness is Subtitle F of the Act, "Repeal of PUHCA" (the Public Utility Holding Company Act of 1935) and Section 1289 "Merger Review Reform."[46] The repeal of PUHCA is straight forward enough, some aspects of federal and state commission access and other provisions were replaced, but the PUHCA requirements on utilities are repealed. The impact of the Merger Review section will depend on FERC's implementation and a full analysis of both sections of the legislation is beyond what can be done at this time. However, most observers seem to agree that this will almost certainly lead to more and larger mergers and perhaps involve oil, natural gas, electric, and other combination companies. This

[45]Lester Lave, Sarosh Talukdar, Kong-Wei Lye, Eswaran Subrahmanian, "Designing Electricity Markets: Are Freshmen or Wind Tunnels More Useful?" Carnegie Mellon University, December 20, 2004. Presented at the Annual Meeting of the American Economic Association, panel on "Lessons from Electricity Deregulation," Philadelphia, PA, January 2005.

[46]Actual repeal of the PUHCA is in section 1263, "Repeal of the Public Utility Holding Company Act of 1935." From the House of Representatives and Senate Conference Report.

will likely mean even greater concentration of the industry, and in particular, increased concentration of ownership of generation resources. If the result is an increase in the concentration of generation ownership, then, as economic theory suggests, the result will be less competitive wholesale electricity markets.

Proponents of the current market structure point out that the RTO system that is currently operating uses a regional, security constrained economic dispatch that combines many of the old original utility control areas into one regional centralized system. The RTO manages congestion using LMP, does real-time balancing of the system, coordinates and keeps the power flows within technical limits (maintaining voltage and frequency), and in general, controls the regional grid operations. The RTO also manages several other markets, such as the day-ahead market and the allocation and auction for FTRs. These markets are, in the proponents view, sufficiently transparent for buyers and sellers to operate efficiently. The advantage to the regional approach is that the generation and transmission resource base is much larger than any one utility used to have and this means lower cost economic dispatch and better regional control of the transmission system. A combination of the size, structure, and the RTOs rules keeps the flow of power in a least-cost, system-wide dispatch. The market imposes a competitively-driven discipline that keeps market power in check. Monitoring and mitigation procedures are all that is needed to check any market power that may arise. Forward markets and hedging instruments are also available to manage risk and to facilitate trading.

Broader dispatching will lead to lower operating costs systemwide than what would occur with separate utility control areas. But this does not lead automatically to the lowest price for consumers. The degree of competition and the market structure will determine that. Also, thus far, PJM has been able to operate the system reliably, despite facing considerable challenges this summer, but there are concerns about how to encourage the building of base load capacity and new transmission in the future.

While it is true that, in general, competition preforms better than regulation to achieve economic efficiency, in many markets it does not always hold true. An unregulated monopoly or oligopoly could lead to the same level or a worse level of inefficiencies as rate-of-return regulation. The inefficiencies would be in different forms, that is, regulated firms generally would have less incentive to operate their plants as efficiently as a competitive firm would. A monopolist, conversely, would have an incentive to operate cost efficiently but would charge a higher price than a competitive firm and would reduce output to less than what a competitive firm would produce. Oligopoly is a market structure that would fall somewhere in between monopoly and competitive firm in terms of charging a higher price and reducing output but would perhaps operate more efficiently than a regulated firm. The overall impact is what matters from a public interest perspective.

There is an apparent assumption that because ISOs and RTOs are operating markets and maintaining system reliability and that markets are active and have forward markets present, that this implies these markets are competitive. This is confusing market activity with degree of competitiveness. This implicit assumption that competition must always be better, *a priori*, forgets that competition is a means to an end, not an end in itself.

Also, it should be remembered that, as inefficient as it may have been in terms of encouraging cost efficiencies, most of the assets that are currently in RTOs were built during a time of traditional regulation. In fact, a common criticism of rate-of-return regulation was that it led to an *over* investment in capital and infrastructure. The industry is now talking about very un-free market-like incentives to encourage investment in base load generation and transmission–including some that are in the just passed Energy Policy Act of 2005. It is not certain at this time how much electricity customers and taxpayers will have to pay in additional incentives and subsidies to achieve the desired level of investment or how we will determine that level.

It is not known with any degree of certainty if there is significant market power in PJM or other ISO and RTO markets. The analysis conducted so far of the ISOs and RTOs themselves is insufficiently detailed enough to warrant a conclusion one way or the other. For example, the Market Monitoring Unit does a good job providing detailed descriptions of the PJM markets, however, more detailed analysis of the markets needs to be conducted. For the reasons described, the conditions are such that is it possible that considerable market power could be exercised. Only an independent analysis will help shed some light on the issue.

An independent analysis of the wholesale market and its potential impact needs to be conducted in a comprehensive and rigorous manner by someone independent of the RTO and with the analytical capabilities and data access to do so. This is needed to characterize the condition of regional wholesale markets and determine the likely outcome of the regional markets on retail prices. This study needs to be a structural analysis to determine whether there is in fact a sufficient level of competition among suppliers or, as discussed, they are operating closer to an oligopoly structure with tacit or other forms of collusion. This analysis needs to be independent of the ISOs and RTOs so that it is not influenced by any single or group of market participants that obviously would have an interest in the outcome of the analysis.

This type of analysis is impossible without access to detailed price and bidding data. Unfortunately, data restrictions limit access to external analysis. Either states or FERC or other federal agencies, need to mandate such a study to allow the required data access. Until this is done we are "flying blind" and operating on the assumption that we have sufficient altitude and that there are no mountain ranges in front of us.

State transition periods have been ending and many of these states, as discussed, are seeing significant price increases. In these cases, customers are seeing the full impact of the wholesale market, including the fuel price increases. Fuel costs have increased across the country, but not all states have seen price increases of size that was summarized earlier in this report, as the EIA data show. For example, coal prices have increased, but West Virginia, a non-restructured state (and in PJM) which produces about 90 percent of its electricity with coal, has had flat retail prices. The reason is that most utilities either have their own coal resources, have long term contracts with coal suppliers, or some combination of their own resources and contracts, so the full impact of a change in fuel prices does not fully impact customers in these cases.

There is not a general one-to-one correlation between rising fuel costs and retail rates, therefore, it cannot be determined how much is attributed to increased fuel costs and what is attributed to other costs, without examining each company or contract for type of fuel used and proportion of each. According to EIA figures, the national average retail price for all sectors from 2004 through April 2005 increased by 3.6 percent. This suggests that, nationally, the full impact of fuel cost increases is not being passed through in rates. Again, this is likely because utilities and other suppliers often have long term contracts for the supply of coal, natural gas and other fuels, have access to their own fuel supply or some combination of both and also have different fuel use mixes. In the case of regulated utilities, fuel cost increases would be passed through fuel adjustment mechanisms, but in proportion to the fuel used. In the case of retail customers in restructured states where the transition period has ended and their price is now determined in the wholesale market, the customers are now taking the brunt of the impact that increased fuel prices is having on wholesale prices, a point that can be seen in the EIA data plotted in this report.

It appears from the data so far, that most retail customers (especially residential) in restructured states where the transition period has ended and the price is now based on the wholesale market are seeing prices increase faster that in the non-restructured states or states still in transition with a price cap. At best, at this point in time, no discernable overall benefit can be seen from restructuring.