Deregulation/Restructuring Part I: Re-regulation Will Not Fix the Problems

by

Lester Lave, Jay Apt, and Seth Blumsack

"However, all would agree that the glass is half empty, and it would be hard to justify all the costs and turmoil of the transition of electricity restructuring based on the results to date." - William Hogan, May 8, 2007, Conference on Competition in Wholesale Power Markets Docket No. AD07-7-000, Federal Energy Regulatory Commission,

Electricity market restructuring is widely seen as having failed. Many of the same groups who pressed for deregulation now find themselves seeking re-regulation. But re-regulation will reintroduce the flaws and problems that led people to seek deregulation; in addition, reregulation will introduce the additional problem of how to value competitive market assets for inclusion in the regulated rate base.

While rate of return regulation performed admirably for almost a century, growing dissatisfaction led to deregulation rather than attempts to fix the problems. Congress and FERC pressed deregulation and almost half the states adopted it. The threat of deregulation led to cost reductions and improved operations, as well as initial multi-year contracts at reduced prices for large customers. Perhaps the greatest benefit was transparency, revealing cost structures and making cross-subsidization difficult.

While the restructured markets have reduced costs, they have not benefited consumers overall. One fundamental flaw is that the hourly power auctions are not competitive. Another is that all generators are paid the market clearing price. After the California debacle in 2000, the RTOs addressed the former problem by imposing price caps and using market monitors to insist that all units be offered into the market at generation cost. The latter problem has not been fixed: since many units did not cover their fixed costs at auction prices, they threatened to stop generating, leading the RTOs to create a capacity market. While the capacity payments motivate generators to keep offering their power, they have not encouraged sufficient investment to provided needed reliability margins, making reliability an issue. Rather than reduce regulation, restructuring has imposed two new levels of regulation.

Montana and Virginia have decided that deregulation is a flawed idea and have returned to a form of regulation. This action ignores the reasons why ratepayers became disenchanted with regulation and sought change. Fixing the problems with regulation is difficult. Transitioning from market-based rates to regulated rates introduces the additional difficulty of how to value assets that will return to the rate base. If they are valued based on current market prices, ratepayers will get no relief from high electric bills. If regulators try to value the assets at less than their current market value, there will be expensive litigation with an uncertain outcome. The political problems cannot be eliminated by simply eliminating deregulation.

In "Deregulation/Restructuring Part II: Where Do We Go From Here?" we discuss changes in market design that would lead to greater competition and fulfill the promise of deregulation.

I. The Accomplishments of Rate of Return Regulation (RORR)

Rate of Return Regulation (RORR) began around 1910 at the request of investor owned electricity suppliers who pleaded that they could not get access to capital in the face of ruinous competition. They sought the sole right to produce and distribute electricity within a fixed territory and were willing to accept regulated prices and a fixed rate of return. Growing demand, a monopoly in their territory, rapidly evolving technology, and the consistent ability to earn their target rate of return attracted investors. Investor owned utilities were able to raise the billions of investment dollars required to build the electricity infrastructure. Together with their public power counterparts, they were able to supply power to almost all US residences and businesses within a half-century. The price (and cost) of electricity fell each year and reliability increased. Reliable, low cost electricity in tens of millions of buildings sparked innovation with major investments in new products, from lighting to television to air conditioning. RORR provided a structure for the rapid development of the electricity system with myriad private and social benefits.

By 1970, the real electricity price (after accounting for inflation) had fallen to less than 2.5% of the level that Edison charged in 1892. Federal and state government programs provided incentives for a mix of electric utilities, including investor owned, municipal, and public power companies to connect almost all residences, even those in remote rural areas. Rapidly rising demand facilitated the introduction of new technology.

II. What Was Wrong With RORR?

The price of electricity rose 50% from 1970 to 1975. The "minor" issues in the RORR structure that had been ignored became major problems. The defects had been hidden by rapidly evolving generation technology that continually lowered generation costs.

A. Growing Technical Complexity: As the grid grew in size and complexity, technical difficulties arose. While ever larger generators had lowered costs for 70 years, the new 1,000 megawatt (MW) generators had unexpected problems. Starting in 1962, many utilities tied their systems together for mutual support. Although this reduced the number of small failures, the interconnections among utilities produced blackouts that affected millions of people beginning in 1965.

B. Over-Investment: The profit that a utility could earn is directly tied to the book value of its assets; the more assets, the greater the potential profit. The desire to build more generation, transmission, and distribution (T&D) was compounded by the fact that in most years, a utility could borrow money (through loans or by setting bonds) at less than the allowed rate of return. Thus, investing in more assets with borrowed money allowed shareholders to earn much more than the allowed rate of return on their equity. For example, if the utility were allowed to earn 10% on assets and could borrow the money at 8%, a $100 million investment would return an additional $2 million per year to stockholders. This "Averch-Johnson" effect motivated utilities to find more investment opportunities, even if they were not really needed. Since regulators demand high reliability, it was easy to justify increased investment as needed to prevent electricity shortages and blackouts.

C. Bureaucratic Complexity of the State Regulatory Process: The state Public Utility Commissions (PUC) operated in a political-legal environment, often taking years to make decisions. The utilities benefited before 1970 when a new generator with low costs came online, since average generation costs fell. The utility was in no hurry to have the PUC act to adjust the price downward since they were earning profits above their target level.

D. Technical-Business Knowledge of the Commissioners: Knowledge of the technology or business of the industry was generally not the most important criterion for selection to the PUC. Rather, state governors appointed political allies, usually lawyers or consumers, often with limited technical or business knowledge. The technical and business issues are sufficiently complicated that even most bright individuals, within a four-year term of office, are unlikely to understand the full implications of the decisions they must make. Many utilities learned to manage the PUC to get their desired outcomes. If, for myriad reasons, a utility doesn't desire to be completely candid in describing its operations and costs, it could present reams of data that would deter all but the most skilled auditors from learning what the utility doesn't want them to know. Commission decisions seesawed between giving the utility what they asked for and denying even fair requests.

E. Political Decisions: The RORR process focused on the issues of greatest concern to the governor and commissioners, sometimes to the detriment of the average customer. Many commissions focused on subsidizing favored groups such as large employers, resolving even unreasonable consumer complaints, and helping the political allies of the governor, rather than delivering low-cost electricity.

F. Revolving Door: Many commissioners went to work for the industry when their terms of office ended, either as company executives or as lawyers. One key to having a good job at the end of the term was pleasing companies while in office.

G. Punishing Risk Taking: Before an asset can go into the rate base, the PUC must find that it is a prudent investment. Since prudency review generally takes place after the asset is constructed, RORR gave utilities a strong incentive not to take chances on new technologies, since they would be denied reimbursement if it didn't work. Since operating costs were generally passed through, utility management had less incentive than private sector companies to keep employment low and boost productivity. One indication of the effect of passing through operating costs is the massive reductions in the utility workforce in the mid 1990s due to the threat of deregulation and other changes.

The one major area where dozens of utilities took on risk was building nuclear power plants. While some utilities were able to build and operate these facilities well, many stumbled badly. Tens of nuclear power plants in planning, site preparation, construction, or even start-up were abandoned due to high costs and public opposition, leading to billions of dollars in losses. The experience in operating nuclear plants was no better. The average availability of nuclear power plants was less than 2/3 prior to deregulation. The Nuclear Regulatory Commission found that many companies were not operating their plants safely, forcing some to shut down for extended periods. The core meltdown at Three Mile Island was a dramatic example of inadequate management.

<u>H. Low R&D Investment</u>: Much of the R&D was done by equipment suppliers rather than the regulated utilities. The utilities in fact spent so little on R&D that in the early 1970s Congress seemed poised to order utilities to pay into a fund for the Department of Energy's R&D. The threat was headed off by the formation of the Electric Power Research Institute, a nonprofit organization that would manage industry R&D. However, utility contributions to EPRI declined for two decades; current R&D spending is extremely low, about 0.2% of revenue. This low level of spending is at variance with the technical problems in the industry and the promising opportunities for new technology.

<u>I. Over-Expansion:</u> One of the largest problems was blamed on RORR unfairly. Utilities had an obligation to serve, requiring sufficient capacity under all circumstances. Increasing demand and the time required to design and build a new plant meant that utilities were always in the process of doubling capacity. The 1973-74 and 1980-81 energy crises caused large recessions, stopping the growth of electricity demand, and leaving the industry with excess capacity. As the unneeded plants, particularly the nuclear plants, came into the rate base, they boosted prices and fueled public complaints.

By the early 1990s, the public demanded change in RORR. An obvious remedy would have been to reform RORR. The customers (led by large industrial companies), political leaders, and the utilities turned to a radical remedy.

III. Reasons for Deregulation

In 1978, the USA deregulated airlines, followed shortly by trucking, ocean shipping, oil and natural gas, banking, Wall Street, and other markets. While there were vocal critics of each law, deregulation benefited most consumers. Public dissatisfaction with the electricity industry led to demands for deregulation. As a reaction to the 1973 energy crisis, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA), eliminating, at least in principle, protected monopolies for electric generation. When the Supreme Court ruled in 1982 that PURPA was constitutional, entrepreneurs entered the market.[1] The success of these early non-utility generation facilities and of deregulation in other industries led to provisions in the 1992 Energy Policy Act encouraging wholesale and retail choice in electricity. FERC promoted competition through Orders 888 and 889, which sought to provide open transmission access and transparent system information to the market. States such as California and Pennsylvania rushed to be first to restructure.

The immediate goals of restructuring were (1) allowing customers, particularly large industrial and commercial customers, to choose their supplier in searching for lower prices, (2) to gain lower prices through competition that lowered costs, (3) to shift risks from consumers to stockholders so that a botched plant would not be charged to rate payers, and (4) to use the forces of competition to speed innovation and improve company management. Additional goals were: (5) decreasing regulation to promote competition and innovation, (6) reducing transition costs or costs of operating the new system, (7) improving plant operations, and (8) allowing utilities to recover stranded costs (so that they would agree to deregulation).

Giving a utility the exclusive right to sell power within an area helped develop the industry, but precluded consumer choice, the foundation of a competitive market. Giving consumers choice was a fundamental change. Economists ascribe much of the dynamic of the US economy to competition among suppliers to improve their products, lower costs, and innovate. People assumed that these forces would work for electricity.

However, while industries such as oil can be competitive from bottom to top, the electricity industry cannot. Local distribution infrastructure is capital-intensive and displays economies of scale, making the retail delivery of centrally produced electricity (along with natural gas and water) a natural monopoly. A competitive challenge to power delivered via the utility distribution system is the possible future growth of distributed generation with microgrids. For malls, large buildings, or industrial parks, these microgrids could compete with the existing distribution system if gas prices allow economic operation of their generators. However, for the near-term future, a competitive market for utility distribution wires is not possible.

Experts differ on whether the transmission system could be competitive. We could imagine a stand-alone transmission line, like a highway with tolls, which competes with other transmission lines. However, once these lines are joined into a transmission grid, the laws of physics make the structure of the grid so interdependent that constructing and operating individual lines makes no sense. In the future, the development of high-voltage DC transmission lines and the installation of economical flexible AC transmission system (FACTS) devices could eliminate the physical interdependence and allow competition with the Regional Transmission Organization (RTO) managing the devices.

The FERC prefers a structure where transmission is controlled by an RTO while the grid ownership can be by utilities or other entities. We agree with FERC on control, but judge that operating the system would be more efficient if the construction and maintenance of transmission lines were controlled by the RTO. Since the owner has no control over a line, building a new line is a passive investment. There is no strategic reason for a utility to build a new line (lines needed for reliability are exceptions). Thus, an unpredicted effect of deregulation has been almost no investment in new transmission lines, despite growing need.

That leaves generation as the part of the system that could be competitive. Restructuring the electricity system has focused on making generation competitive. The rules for transmission and local distribution need to be designed to facilitate competition and to prevent the owners and these parts of the system from extracting all the profit.

IV. Has Deregulation Worked?

The threat of deregulation in the early 1990s led utilities, including those in states that ultimately did not restructure, to reduce costs, improve operations, and initially offer multi-year contracts at lower pries to desired customers. Regulators, utilities, and customers assumed that competition would force down costs. The restructuring created transparency in pricing, meaning that cross-subsidies had to be eliminated or made explicit – causing many subsidies to be eliminated. Restructuring shifted the focus from benefiting favored groups, keeping labor peace, focusing on reliability, and managing conservatively to lower costs and prices.

A dozen reports attempt to test whether restructuring has lowered prices.[2] Other reports [3] examine consumer choice, the cost of setting up and operating the RTO, and the use of LMPs in a restructured industry.[4] With a great deal of money at stake, some reports appear to have been commissioned to advocate a position rather than conduct an unbiased analysis. Evaluators have disagreed about the criteria for judging success and what would have happened in the absence of restructuring; some contend that full evaluation is not possible until the restructuring process is completed in 2011 or after.[5]

We find much of the disagreement to be specious. Since the first states deregulated in 1998, there is almost a decade of experience to consider. In our judgment, the outcomes of current policies are clear, even if they have not been realized fully. Kwoka's 2006 review of deregulation[5] is particularly careful. Unfortunately, he sets up criteria that no study meets, and perhaps no study could meet. This leads him to conclude that one cannot answer the question at this time. However, legislatures in Connecticut, Maryland, Maine, Michigan, Ohio, Pennsylvania, Texas and other states, together with Congress and FERC, must make judgments about whether to press forward or reverse restructuring, as well as how to control prices and increase investment. Virginia and Montana have resolved the issue by re-regulating. Decision makers don't have the luxury of waiting years for a definitive answer; they need guidance now.

We evaluate deregulation in terms of the four primary goals: (1) allowing customers, particularly large industrial and commercial customers, to choose their supplier to get lower prices, (2) to gain lower prices through competition that lowers costs, (3) to shift risks from consumers to stockholders, and (4) to use the forces of competition to speed innovation and improve company management.

<u>A. Customer Choice:</u> Large customers have been allowed to choose their generation provider in all restructured states. Whether that has resulted in lower prices is addressed below. Although choice for residential customers is allowed in many states, it has all but disappeared in most states where it had occurred.[6] Several important lessons have

emerged from customer choice. First, about 10% of customers signed up for renewable power and were willing to pay a premium for this green power. Second, the large industrial plants sought after by state and local development agencies have not been regarded as the most desirable customers by deregulated generators or competitive retailers. Instead, large commercial customers, including hospitals and universities, have emerged as the most desired customers.[7] In Western Pennsylvania, some of these large commercial customers have been able to buy electricity at a considerably lower price than large industrial customers. In several Mid Atlantic states, the average industrial customer pays a higher price, relative to commercial and residential customers, compared to the prices under regulation. Third, customer choice led to innovative new companies that purchase electricity for large customers. These intermediaries have increased efficiency by bundling together customers with compatible usage patterns in order to secure lower wholesale prices.

<u>B. Did Deregulation Lower Prices?</u> Several studies have examined whether prices have fallen as a result of deregulation. Since there are still mandated price reductions in some areas, a definitive answer must wait until restructuring is completed. However, in the majority of areas where the mandated price reductions have expired, load serving entities (LSEs) have requested large rate increases, such as Baltimore Gas & Electric.[8] This pattern is clear, although it is not clear whether the price increases will be greater than in comparable states that did not restructure.

The best answer to the question comes from examining industrial prices, since they generally were not subject to post-restructuring price caps, and since they were expected to be the largest beneficiaries of deregulation.[9] A comparison of price changes over time, from the years prior to restructuring to the present, contrasting states that restructured with those that had not restructured, provides the best information of the effect of deregulation on prices. Apt found no evidence that restructuring had lowered industrial rates relative to the years before restructuring or to states that had not restructured. An independent econometric study that attempts to control for many factors that influence price, found that restructuring did not lower prices.[10]

<u>C. Shifting Risk to Stockholders:</u> Utilities were able to obtain capital at favorable rates under regulation because of the low risks they faced. Restructuring shifted the risks from ratepayers to companies (shareholders), a fundamental change in the financial structure of the industry. The California debacle in 2000 put one investor owned utility into bankruptcy and essentially bankrupted the other two. If investors had not perceived the large increase in risks for utilities previously, this experience was a dramatic warning. The result was that investors regarded generating companies and even the regulated load serving entity (LSE) as highly risky, demanding higher rates of return before they would provide capital. For several years after the California fiasco, investors were trying to sort out the risks and were unwilling to provide capital except at high rates. Raising the cost of capital causes a major increase in the costs of new plants. The rate of investment in restructured states appears generally to be lower than in RORR states, in part due to investors demanding higher rates of return to compensate for the additional uncertainty brought about by restructuring. For example, NYISO and CAISO report shortages of

generation capacity that could lead to blacking out customers in the near future. In contrast, states in rapidly growing areas that did not restructure, such as the southeast and southwest, have been adding capacity to meet demand.

Shifting all of the risk of generation from ratepayers to owners does not appear to have benefited the former. The PUC managed risk on behalf of electricity customers. Emphasizing reliability and resource adequacy led to excess capacity and higher rates in the 1980s and 1990s. While investors in large companies are likely to be less risk averse than residential customers, and RTOs may be able to manage risks (such as demand fluctuations) better than generating companies, the shift in risk made investors leery, leading to higher interest rates, thus higher costs, and a slow rate of investment. The lower investments decreased reserve margins, increasing blackout risks. Research is needed to quantify the risk-return frontier and select the price-risk tradeoff preferred by customers.

D. Did Restructuring Speed Innovation? Competition has put immense pressure on generators and LSEs to lower costs. One of the first casualties in cutting costs was the already anemic R&D budget. Companies in restructured states have been unwilling or unable to make investments that don't have short payback periods. Thus, there has been less opportunity for innovation and introducing new technologies in restructured states.

E. Did Restructuring Decrease Regulation? The wholesale generation market has not actually been deregulated or even seen less regulation. While FERC allows generators to charge market based prices, these generators are subject to extensive market monitoring by the RTOs and FERC. If anything, there are more layers of regulation now. In addition to the state and federal regulation under RORR, the industry is subject to regulation by the RTO (which extends FERC's control). The RTO regulation, especially by the market monitor, is more detailed and intrusive than any that the industry had under RORR. The August 14, 2003 blackout led Congress to create a regulatory agency, the Electricity Reliability Organization (ERO), tasking it with setting mandatory reliability standards, adding still another layer of regulation. While the reliability standards under RORR were voluntary (the PUC could enforce them, if desired), the responsibility for reliability was clear. In the restructured system, the responsibility for reliability is diffuse.

The basic problem with the restructured market design was revealed in California in 2000: generators withheld capacity and offered prices much higher than would have prevailed in a competitive market. Putting a price cap on the market prevented the price from going higher, but did not make the market competitive. Each RTO has devoted considerable resources to establishing a market monitor who makes sure that generators don't withhold capacity and do offer their capacity at marginal cost, at least when prices are high. This market monitoring is considered to be a reasonable substitute for competition by many, but still has major flaws, in additional to being much more obtrusive than RORR. This sort of detailed regulation leads to a "cat and mouse" game where the generators think of ways to violate the rules while the market monitor tries to catch the offenders. As noted above, the price caps, pricing structure, and market monitoring have scared investors, leaving many areas (particularly densely populated areas in the Northeast) facing the prospect of capacity shortages.

F. Transitional Costs and Problems: The failure of MISO to understand what was happening and to take appropriate action contributed to the blackout of August 14, 2003, as did the failure to invest in modern situational awareness technology. We respectfully disagree with the investigation report's conclusion; in our judgment deregulation contributed to transforming a local blackout into a regional one. In the restructured market, the responsibilities of FirstEnergy and other generators were unclear, with much of the responsibility passing to an under-prepared MISO.

Creating the RTOs is reported to have cost hundreds of millions of dollars for each RTO; Batemen and Smith find that the RTOs collectively spend more than $1 billion per year. RTO costs have a large fixed component and so the cost per MWh is lowest for the largest RTOs.[11] This suggests that merging some RTOs, such as New York and New England, might lower costs. While the costs of PJM per MWh are falling, those of New York and New England are larger and are rising. These costs do not include the costs incurred by companies due to the restructuring.

G. Improving Plant Operation: A major benefit of restructuring was that many nuclear power plants and some other generators were acquired by companies that were expert in managing these plants. As a result of the ownership changes and other forces, nuclear and other generation plant operations became more efficient and reliable.[12] The fleet of nuclear power generators in the US increased their availability to more than 90% from just over 70% during the period since 1996, when deregulation first began at the state level. The US coal fleet increased its capacity factor from 55% to 60% during the same period. The data don't show that the improved operations and lower costs of these plants resulted in lower electricity prices to consumers.

Restructuring led to other changes; some were desired and some represent collateral damage.

H. Energy Efficiency Programs: Restructuring ended almost all electricity conservation programs (California continued an aggressive program). Many utilities were no longer required to undertake these programs and shed them to reduce cost. The conservation programs have been shown to be effective and cost-effective in many cases.[13] The escalating costs of new generators and transmission lines, together with the public opposition to siting new assets, strengthens the case for pursuing conservation programs. Unfortunately, there is little indication that energy service providers will take up these programs without subsidy. This problem is termed "decoupling;" since the utilities earn a profit for power sold, they have no incentive to reduce the number of kWh sold. A minimum policy goal is to find a market structure that decouples the utility's revenue stream from its load. A better goal would create positive incentives for a utility to reduce load.

I. Entering Other Businesses: Restructuring encouraged unregulated utility subsidiaries to pursue acquisitions of unrelated businesses as well as of electricity companies in other countries. To date, few of these ventures have been successful.

J. Incentives for Market Manipulation: The restructured market, particularly paying market clearing prices to all generators, gave an all but irresistible incentive for generators to manipulate the auction market. If generators are able to withhold an inexpensive generator, forcing the RTO to accept a high cost generator in its place, all units will be paid the higher market clearing price. As demonstrated in California in 2000, this manipulation is easy to accomplish and is enormously profitable. As demonstrated by the recent purchase of new inefficient (simple cycle) gas generators by utilities owning baseload coal plants, manipulation is a contemporary problem as well.

To stop this manipulation, an RTO has a team of market monitors who watch each generator closely to see that there is no withholding and that plants offer power into the hourly market at competitive prices during periods of high demand. However, market monitoring is obtrusive and expensive, both for the RTO and company, and in general cannot stop all prohibited behavior or manipulation.

K. Investment Incentives: Deregulation proponents didn't predict that convincing investors to add capacity would be a problem, since it is not a concern in competitive markets. A capacity shortage leads to higher prices and profits, which attract investors. While the owners of low-cost baseload generation have had their assets appreciate considerably in value, other generation owners have not earned profits that make new investment attractive.[14] NYISO and other systems operators have attempted to ensure that sufficient capacity will be available to meet load by establishing capacity markets. These markets offer payment to owners that guarantee that the specified levels of generation will be available during the specified period.

While the capacity markets are designed to ensure that existing capacity is available, they do little to encourage investing in new plants. The capacity markets have historically looked ahead a year or less, although some new designs are looking ahead several years. A several-year period is long enough to get a new gas turbine built and operating. However, building the plant requires that investors expect to recoup their investment over the lifetime of the project. Since there is no guarantee that there will be capacity markets in the future or that regulators will allow high prices during peak demand periods, the profitability of the plant is uncertain. Unless investors believe that these capacity markets will pay similar amounts over the next several decades, the capacity payments will increase the profits of generation owners without adding to long-term capacity. A new institutional arrangement is needed to induce building new generation and transmission capacity, as well as pay for existing capacity. PJM is attempting to address this issue by introducing a capacity market that offers contracts up to five years forward.

L. Industry Profitability: Bodmer calculates the profitability of 14 companies since deregulation.[15] Companies that formerly were regulated have enjoyed high profits by several measures while merchant generators have not fared well. The profitability of some companies was wasted on unwise investments, but those companies that focused on their electricity business earned attractive rates of return.

In retrospect, it is easy to see that the value of low cost baseload generators was greatly enhanced by an auction system that pays generators based on the market clearing price rather than average or marginal cost. The deregulated structure ensures that the low-cost baseload generator will be paid its generating costs at the worst times and will be paid the generating costs of more expensive plants the rest of the time. This created a bonanza for the nuclear and efficient coal plants.[16] In contrast, the highest cost peaking plants operate only a few hours per year and are paid, when forced to offer capacity at competitive rates, at most their variable generating cost; these plants never have a chance to earn their fixed costs. To keep these plants operating, the RTO established capacity markets, which had the unintended consequence of further enriching the profitability of the low-cost baseload plants.

M. Has Deregulation Benefited Customers? We conclude that restructuring has so far failed to accomplish its major goals. Despite enormous upheaval and expenditures, costs are not lower, there is little or no choice for residences and small industrial and commercial users, and large industrial customers have not been able to find lower prices. Large, recent price increases in restructured states indicate that the comparison with RORR states is unlikely to improve by waiting longer. While restructuring the electricity industry has accomplished some of the primary objectives and improved industry efficiency, after the rate freezes expire, we judge that most electricity customers will not have benefited from restructuring.

V. Is Reregulation a Solution?

The large price increases that have followed unfreezing retail prices and the rising prices in states like California, Maryland, Virginia, Illinois, and Montana have created intense public unhappiness with restructuring. State regulators, many investors, and industry analysts look at the other results of deregulation and see problems. FERC stopped trying to get states to adopt its standard market design. At this time, no regulated state is planning to restructure.[17] California and other states have at least temporarily pulled back from deregulation and public officials in Connecticut, Maine, Maryland, Michigan, Ohio, Pennsylvania, and Texas are discussing reregulation; Virginia and Montana have reregulated. Virginia has not returned to traditional RORR. Dominion’s rate of return will be set by the Virginia PUC, but not based on costs. Rather, it will be based on the financial performance of a group of “peer” utilities in the Southeastern U.S.

However, the costs of immediate reregulation are high, except in states like Virginia and Ohio where the utilities did not divest their generation assets. Thus, no immediate change is likely to occur, absent demonstrating a superior market design for restructuring or a slow process of reregulating, one plant at a time.

Unfortunately, RORR still has all the flaws that led states to turn to deregulation. Reregulation would bring back these problems, from over-investing to regulators being more concerned with political issues than getting the lowest prices for electricity. Could there be a renaissance in which public utility commissions were selected on the basis of their technical and business knowledge of the industry? Could the renaissance get companies to be fully cooperative with regulators, confessing their mistakes and mismanagement? These flaws might not look so bad compared to the California experience, but recall that they were sufficient to get many states to pursue deregulation in the first place.

In addition, a return to RORR would impose higher costs than if the state had not restructured, since the generation assets would be valued at higher prices. To return to RORR, each asset must be put into the rate base; the value at which assets are brought back into the rate base is inherently contentious since the current owners would like to get as high a price as possible. Many generator assets were sold in the restructured market. Advanced natural gas plants, for example, were sold for much less than book value. Some of the low cost baseload plants were sold and then resold later at much more than the original sales prices. We presume that utilities that sold their assets for less than book value have been compensated for the loss by the charges for stranded costs. If so, they have no direct stake in the revaluation process, other than having an aversion to charging much higher rates for electricity because of a high value for the assets in the rate base.

Determining the value at which assets would be put into the rate base would be a long, costly process. Low-cost baseload generators, such as nuclear power plants, are highly profitable. The owners would claim a high market value. In finance theory, the value of an asset is the present discounted value of future cash flows. These low cost generators are profitable and promise to provide large profits in the future. We caution that bringing these low cost assets into the rate base at current market value would simply ensure that electricity generation costs would remain high during the life of these plants.

Consider a hypothetical nuclear plant that cost $3 billion to build, was sold for $500 million in 1998, leaving the utility with $500 million of stranded costs, and now has a market value of $4 billion, with a remaining lifetime of 20 years. We assume that the stranded costs have been paid, putting this plant into the rate base at $4 billion, assuming that utilities are able to earn 11% on their assets, would allow the owner to recover $640 million per year. If so, the cost of electricity from this plant would be about 10 cents/kWh, including 8 cents/kWh of capital costs. If the plant had never been sold and $500 million of stranded costs had been paid, the book value of the asset would be $500 million. If so, its cost of electricity would be 3 cents/kWh, with only 1 cent/kWh of capital costs. Thus, placing these assets into the rate base at market value would build in the expected future profits under the current system, meaning that customers might not benefit from reregulation until the current assets were retired.

The above value could be disputed, but there is no dispute as to the value of the plant when a new owner is willing to pay a high price for a low cost generator, as has occurred in Texas and with some nuclear plants. Valuing the plants at less than the sales price appears to be taking property without fair compensation. Even utilities that had not sold assets could claim that the assets should be valued at fair market value, since the old value became irrelevant when the market was restructured. We predict years of contentious litigation.

Valuation could also lead to a cat and mouse game. For example, a state might impose a tax on electricity, lowering the profitability of generators. The plants could be brought into the rate base at the lower value and then the tax could be rescinded. Another approach would be for the state to subsidize new capacity, lowering the price of new plants and the profitability of existing plants. The one certain conclusion is that valuation would be contentious leading to litigation and political challenges. There is a realistic possibility of actions that could disrupt supply, causing customers to lose power.

One suggestion is that the PUC instruct the LSE that they could not recover costs that they paid for power above a level, such as the long-term cost of new generation (this is against the rules in some RTOs). We fear that such a price-cap policy would lead to a confrontation where the generators refused to sell power at the set prices, leading to blackouts.

VI. Conclusion

Rate of return regulation provided an environment that allowed the electric power industry to transition from an initial period of chaotic competition. During the industry's decades of strong growth and technological advancement, it generally served consumers and the industry well. The problems and inefficiencies inherent in RORR were not fully apparent until the 1970s, when costs soared due to high fuel prices and poor (and expensive) decisions by utility managers. Deregulation seemed to be the solution at the time, due in part to pressure from consumers and in part to generally successful experiences with deregulation in other industries.

Electricity market restructuring is widely seen as having failed. Even deregulation's strongest proponents must be disappointed with the results. The failures of electricity deregulation in the U.S. have made regulation look attractive by comparison. Thus, many of the same groups that pressed for deregulation in the first place are now seeking re-regulation. Two states have already re-regulated in some form and several others are talking seriously about following suit. Re-regulation is not, however, as simple a solution as it may seem. Not only will it reintroduce all of the flaws and problems that were inherent in regulation in the first place, but it would introduce the additional problem of how to value competitive market assets for inclusion in the regulated rate base.

Part I of our article has set up the problem in some detail. We are not ready to give up totally on deregulation. In Part II, we describe a proposed change to the competitive market design which we believe will bring the benefits of competition while providing adequate investment incentives and decreasing the need for heavy-handed market monitoring.

Deregulation/Restructuring Part II: Where Do We Go From Here?

We reject calls for reregulation. Our alternative is to solicit offers for long-term contracts that specify fixed and generating prices for each plant. The contracts would specify the number of times a generator could be asked to shut down, as well as the availability and reliability of the unit. Units whose offers are accepted would be paid their fixed offer if they complied with the terms of the contract and their generation offer for each MWh they were asked to supply.

In Part I, "Deregulation/Restructuring: Re-regulation Will Not Fix the Problems," we reviewed the challenges facing the restructured U.S. electricity industry, and discussed how the temptation of returning to regulation would neither address these challenges nor solve any problems. We described the history of electricity regulation, from the initial highly competitive market to the demand for regulation, and spectacular growth of the industry under the regulatory structure. After the early 1970s, the flaws of regulation became more important and evident, culminating in the 1990s in the market structures still with us today. We evaluated the performance of restructured markets and found, except for mandated rate reductions, no data indicating that consumers had benefited from the change. As the mandated rate reductions have expired, large rate increases have followed angering residential, commercial, and industrial customers. Montana and Virginia have reversed deregulation, returning to some form of regulation. Many other states are discussing a return to regulation. We are not ready to write off deregulation as a bad idea. First, returning to regulation would also mean re-introducing the problems with regulation that originally led to calls for deregulation. Correcting these flaws would be difficult. More importantly, the problem of valuing assets as they return to the rate base would be extraordinarily contentious. If the current market values of the assets are used, ratepayers will essentially be locked into high electric rates for decades. If the assets are valued at less than market prices, there will be expensive litigation with an uncertain outcome.

We are thus left with the question of where to go from here. In this article we propose changes in the current market design that would make the restructured markets competitive and deliver many of the benefits of deregulation.

I. Changing Market Design to Realize Competitive Benefits

The central issues in designing a competitive market for electricity are:

A. Are current electricity markets competitive?
B. Can hourly auction markets be made competitive (no generator can influence price)?
C. Who should ensure that the mix of fuels and technology reduces risk?
D. Who should bear the risks under various sources of uncertainty:

    1. Future demand level (excess demand or supply)
    2. Future fuel prices

3. Future environmental regulations (especially greenhouse gases)
4. Future labor costs (wages, strikes, …)
5. Acts of nature (hurricanes, etc.)
6. Terrorism (human induced losses) ?

E. To what extent can (should) electricity decisions be isolated from politics?
F. How to resolve conflicting and overlapping regulation?

We now discuss each of these issues in turn.

A. Are Current Electricity Markets Competitive? Economists define a competitive market to be one where no participant (seller or buyer) can influence the price. Participants are free to offer whatever price they choose, but they would sell nothing if they offer a price higher than the market price and would be foolish to offer a price lower than the market price. This ideal may never be realized in practice, but some markets are good approximations to being competitive while others are not.

Competitive markets have the additional virtues of forcing producers to continue reducing costs in order to stay competitive; they force buyers to face the additional costs of a unit to be purchased. If regulators try to force a non-competitive market to act competitive, the result may display few of the virtues of a regulated market. For example, if regulators force price to be too low, owners may stop producing or stop investing in new facilities. As a result, regulators would continually find that they had to apply an additional patch, such as a capacity market, to keep the system operating.

PJM, NYISO, ISONE, MISO and the other restructured markets are not remotely close to being competitive by the above definition. They may produce prices that are generally close to competitive levels, but these are the result of a highly administered market, rather than an economically competitive market. A market monitor watches the offer prices closely as well as whether generators are being withheld from the market. The monitor can order a generator to provide power at marginal cost and can order a generator to justify why a unit is not in service.

Economic theory details the many benefits of competitive markets. Markets that are "workably" competitive can also provide benefits, but are supervised by the anti-trust authorities. To see if the RTOs are "workably" competitive, we would look at the number of times the monitors intervene or, more generally, the extent to which suppliers constrain their behavior because of their fear of the market monitor. Using this criterion, we conclude that PJM is neither competitive nor workably competitive.

PJM's 2005 State of the Market Report notes that, on average, less than 0.5% of the supply offers have been offer-capped or mitigated in each of the past few years.[18] This is an argument either that the market is economically competitive or that the market monitors have scared generators into behaving competitively. Without seeing more detailed data on offer-capping, it is hard to tell which is true. If the PJM market were responding to competition rather than fear of market monitors, we would expect to see very high prices during high demand hours since pivotal suppliers would have market power. The lack of market power during the high demand hours indicates tough market monitoring.

The point is that the virtues that economic theory say will come from competitive markets should not be expected to result from the current restructured electricity markets. Current markets produce benefits, but not those coming from competitive markets.

B. Could Hourly Auction Markets Be Competitive? Electricity has three important attributes. First, very large scale storage is essentially too expensive. Second, if there is a significant supply shortage, there is likely to be a blackout. Third, significant network externalities mean that a supply-demand imbalance in one area of the grid can cause service interruptions that cascade to other parts of the grid. Thus, there are difficulties if supply and demand don't always match. This means that at a period of high demand, large generators are "pivotal" in the sense that if any large generator withholds supply, demand will exceed supply and there could be a blackout.

One way to avoid this situation is by having sufficient additional generation capacity that no generator is pivotal. Unfortunately, experiments at Carnegie Mellon[19] and Cornell[20] show that hourly auction markets are ideally designed to teach participants to manipulate the market to raise profit. They find that suppliers are able to learn to raise price above competitive levels even when no single firm is pivotal. This is true even when generation capacity is twice as large as demand. These results suggest that forcing all generation to be sold in an hourly market, as happened in California, will not lead to a competitive market.

The experiments suggest changing the market design to have buyers participate. Rather than the RTO buying power to meet a specified target, the RTO could get demand schedules from customers and allow customers to offer demand reductions to find a market clearing price and quantity. Alternatively, the buyers and sellers could engage in bilateral negotiations to set individual contracts. The experiments suggest that bringing customers into the process would mitigate much of the market power of generators. Large customers could participate directly while small customers could be represented by an aggregator. PJM allows load aggregators to offer demand response into the system now, but there is little volume, either because aggregators have not seen the opportunity or there are other difficulties.

The PJM market has only 15% of supply sold in the hourly market with 85% sold through bilateral contracts. Whether having the vast majority of power sold outside the hourly market promotes competition depends on what sets the price in bilateral contracts. We believe that the principal influence on price in the bilateral market is the market clearing price in the auction market. Would a generator be willing to sign a bilateral contract for $30/MWh when the hourly market price has been $60/MWh? A supplier is unlikely to accept a bilateral contract at a price less than the auction market, accounting for risk preferences, since the supplier could sell the electricity in that market. Even existing bilateral contracts are likely to be renegotiated if their prices are far from the average hourly price. That means that even having 95% of transactions in the bilateral market is not going to result in competition, unless the auction markets are competitive.

The point is that having an hourly auction market of the sort currently run by the RTOs where demand is fixed and unresponsive to price will not facilitate competition, even if only a small proportion of power is traded in the hourly market. Designing an electricity market that will be competitive is far from easy or straightforward.

C. The Fuel-Technology Portfolio: In a regulated system, a utility was motivated to consider the portfolio of fuels and technologies for generation in order to maintain reliability and hold down future costs (to avoid a rate case). In the restructured system, no generation owner is responsible for reliability or resource adequacy, although the RTO is responsible for reaching aggregated resource adequacy targets. No institution has responsibility for ensuring that the portfolio of fuels and technologies for generation will provide reliable, minimum cost generation. In the restructured system, new generation and transmission is added one unit at a time by individual companies whose incentives have little or nothing to do with the long-term costs and reliability of aggregate supply. There is no explicit consideration of the portfolio aspects of the decisions.

The RTO or state PUCs must assume responsibility for assuring that new investments are compatible with a fuel-technology portfolio that has a reasonable risk-cost tradeoff. We don't minimize the difficulties of making good decisions, but emphasize that these decisions have always been made by vertically-integrated utilities and state regulators; almost any decision is likely to be better, for example, than the vast investments in natural gas generators starting in 1999.

D. Who Should Bear the Risks? Under RORR, rate payers bore essentially all of the risks. State regulators could delay rate increases but, absent a finding that the utility did not act with reasonable care, the utility was entitled to earn its rate of return. In practice, the PUC often delayed rate increases or lowered reimbursement because rates had given too high a rate of return in the past or for other reasons. In some egregious cases, such as the Seabrook nuclear plant construction, management was faulted and not allowed to recover full costs. More generally, rate payers have had to cover the costs even when regulators made the mistakes, as in approving too much capacity expansion, setting up a market design for deregulation that encouraged market manipulation, or freezing rates so that large rate increases were needed when the freeze ended. Deregulation was designed to shift the risks of generation from rate payers to stockholders.

Deciding who should bear a particular risk turns on three elements: 1. who has the best relevant information, 2. who can most easily take actions that lower the cost of an unanticipated event, and 3. who has the least risk aversion. The first element leads to better decisions, the second element lowers the costs for an unexpected outcome, and the third lowers the premium that must be paid to assume the risk.

After deciding who should bear the risk, it is important that whoever is managing the risk should have a stake in the outcome. One way of doing that is to have the manager's profit rise or fall, depending on how well the risk was managed. For example, at one extreme, the generation contract could specify a fixed price for the life of the plant with no provision for adjusting the price as fuel price changes. This puts all of the risk on the generator. The other extreme would be to pass all of the changes in fuel price through into the electricity price. Neither extreme is likely to produce low cost electricity. Putting all the risk on the generator for 30 years is likely to lead to a high risk premium. At the other extreme, passing all the change in costs through removes any reason for the generator to seek lower priced fuel.

Getting lower priced electricity requires sharing the risk so that both the customer and the generator bear part. Since neither the generator nor the customer has much ability to forecast fuel prices over the next 30 years, it is reasonable to put most of the uncertainty on the customer, while still having enough risk on the generator to motivate a search for the lowest price. For fuel, the customer might be responsible for 90% of the uncertainty and the generator for 10%. This will be explained in more detail below.

D.1. Uncertainty in the Future Demand Level: Demand has increased in nearly every year since electricity was marketed. However, it can take ten years to build a new baseload plant and so a utility must build for future demand that is not predictable with confidence; when demand increases less than expected, the utility can be left with excess capacity. Under RORR, the utility was responsible for satisfying demand and regulators insisted that they have large reserve margins; thus, utilities had little or no penalties for having too much capacity. This asymmetric loss function led to building a large “reserve” of generation and transmission capacity.

Shifting the loss to stockholders turns the loss function on its head. Generators are no longer responsible if there is insufficient generation and they bear the costs if there is too much capacity, since the excess capacity in not used. Thus, generators are reluctant to build capacity until they are certain they can get an attractive return on their investment and the RTO, which is responsible for getting sufficient capacity, is increasingly worried about insufficient capacity and blackouts. This market design would be expected to lead to little or no excess capacity and an increase in power shortages.

Each state’s PUC and the LSEs have as much or more information than any other institution about future demand levels. Both the PUC and LSEs are likely to be less risk averse than investors for an individual generator. The LSE is likely to be able to act most quickly if the demand forecast turns out to be too high or too low. For these reasons, some combination of the PUC and LSEs should continue to forecast future demand. However, it is the LSE owners who bear most of the cost if the forecast is wrong; they should make a profit for a good forecast.

Capacity markets that look ahead only six months, 1 year, or even 5 years will have little effect on building new baseload capacity. Only if the capacity payment were so high that the investors recovered their full fixed costs during the period of the capacity auction would investors feel confident in building a new plant.

Another problem with the capacity market is paying the market clearing price to each generating unit. Paying a single price to all generators will pay almost all too much in order to give sufficient compensation to the most needy.

Our recommendation is to have the LSE be willing to extend capacity contracts to the life of the plant and require the plant to offer both fixed and variable prices, as outlined below.

D.2. Uncertainty in Future Fuel Prices: Fuel prices, particularly for natural gas have been highly volatile and are likely to be volatile in the future. After the 1973-74 oil embargo, most regulators allowed fuel costs to be passed through automatically with no regulatory action. If there had been long regulatory delays in adjusting electricity rates for fuel price changes, many utilities would have had a hard time paying their expenses.

Passing though fuel prices gives the wrong incentive in two ways. First, the generator has no incentive to find lower cost suppliers or bargain for better contract terms. Indeed, they are likely to choose a higher cost supplier who promises better service or who otherwise relieves the generator of worries or non-fuel costs. Second, the generator need not think of fuel price volatility in selecting the fuel type for a new plant. Natural gas prices have been much more volatile than coal prices. This need not worry a generator, since the fuel prices will be passed through.

We suggest that generators bear some small portion of the changes in fuel prices, say 10%, so that they are motivated to search for cheaper fuel. A 10% cost share would also induce the generators to give some attention to future price volatility in selecting a fuel for a new generator. What we are proposing is a form of performance-based regulation. Vermont's public service board recently approved a similar arrangement for Green Mountain Power.[21]

D.3. Changing Environmental Regulations: Environmental discharges of pollutants, air, water, and solid waste, have been subject to increasingly stringent regulation over time. Pulverized coal plants have had to bear the most costly environmental retrofits while nuclear plants have had to bear few environmental costs, with natural gas in between. Under RORR, the environmental retrofits, additional operating costs, and costs of discharge permits are all legitimate expenses to be recovered from rate payers.

Continuing to pass these costs through to ratepayers provides the same two wrong incentives as for fuel price increases: first, the company is not motivated to find the cheapest way of meeting the pollution standards and second, the company need not think about future regulations in choosing a fuel and technology. For example, mercury emissions are unlikely to be the last toxic emissions from coal plants to be regulated. Since coal contains virtually the whole periodic table of elements, a pulverized coal plant is likely to face future environmental retrofits. In contrast, a coal gasification plant would find it easier and cheaper to control additional toxic discharges.

The most likely major discharge to be controlled will be carbon dioxide. A pulverized coal plant will bear the greatest penalty, with natural gas bearing a smaller penalty, and nuclear having little or no penalty. A coal plant could be designed for future retrofit to separate and sequester the CO_2.

Below, we suggest that the generator bear a portion of the retrofit costs in order to provide an incentive to find the least costly retrofit and be motivated to select a technology that will require less future retrofitting.

D.4. Future Labor Costs: Under RORR, operating expenses, including labor costs, are passed through to ratepayers. This pass through erodes the generator's incentive to hold down costs. When faced with a strike, the generator will be penalized for a work stoppage that leads to a blackout, while it bears little or none of the costs of granting the pay raise and averting the strike.

Again, we propose sharing the labor costs risks between the ratepayers and the generators. However, we would ask the generator to pay a larger share, 25-50%.

D.5. Acts of Nature: The owner of the generator and transmission lines is in the best position to decide how to protect her investment, given the risks of natural disasters. There should be some cost sharing to motivate the owner to give attention to the correct choice of materials and construction, and of protection of the infrastructure. We suggest a 10% copay.

D.6. Terrorism: The choice of materials and design influences the attractiveness of the target and the amount of damage that can be done. Even though the owner of the generator and transmission lines has no real knowledge of the extent of terrorist threats, there should be a small copay to provide incentives for concern about the design and materials. The owner might have to pay 5% of the loss from a terrorist event.

E. To What Extent Can (Should) Electricity Decisions be Insulated from Politics? The importance of electricity to all aspects of the economy and lifestyle mean that society and elected representatives will insist on having some voice in construction, choice of technology, and pricing of electricity. State legislatures and Congress intervened in the current market to change the market design from RORR to its current structure. They have repeatedly intervened again when the market design displayed problems, there seemed to be market manipulation, or rates were rising quickly.

Problems with the current market design suggest seeking legislative and regulatory help in changing the market design. However, we remind everyone that seeking legislative or regulatory help in changing the current market design puts the issue into the political arena. The result will not be a market design optimized to produce competitive benefits, but rather a design that has been influenced by pressure groups, special interests, and politicians and regulators with their own agendas. The result may not even represent an improvement over the current system. The electricity system is too important to delegate to technical experts. It affects consumers, companies, economic development, and regional development. Each special interest group will fight to craft a design that benefits them, not society generally. The resulting design could easily be hijacked by special interests and be detrimental to the public interest, as occurred in California.

F. Conflicting and Overlapping Regulation: At present, a "deregulated" utility is regulated by its state PUC, the RTO, FERC, and the ERO. FERC has authority over the RTO and ERO, but the PUC is supreme in intrastate decisions such as setting electricity rates. The RTO can request that someone build a generator or a transmission line, but they cannot order it; the PUC sets rates to customers and so controls reimbursement for the investment.[22] Under the 2005 Energy Policy Act, FERC can facilitate the construction "national interest transmission corridors" but only after all other channels have been exhausted.[23] The potential for conflict is real and has arisen, as when Connecticut disagrees with ISO New England concerning the need for additional transmission in its state, or the current conflicts over a planned transmission line through Southwestern Pennsylvania to serve customers along the Mid-Atlantic seaboard.

Congress did not resolve these conflicts in legislation ordering FERC to press for deregulation. There is a constitutional issue as to whether Congress can usurp state power over intrastate electricity issues. The conflicts among the regulatory agencies are likely to become more acute in the future. While FERC can resolve the issues under its control, it cannot order the PUCs to act.

II. Short-term Actions to Lower Prices

Recent offers for long-term contracts in eastern PJM have been at rates of about \$100/MWh.[24] These high offer prices might result from expected increases in costs, (such as fuel prices or environmental rules not covered by the contract), risk aversion, (due to uncertainty about future LMP or other rules), or from exercising market power.

Several reforms could be accomplished quickly, at little expense, and without fundamental change to the current RTO structure to make the current auction markets more competitive. If these changes were effective, they could obviate the need for more radical changes. These short-term reforms are needed now. The RTO could take four steps to reduce the offer prices. We suggest:

A. Customer participation in markets. Rather than having the RTO assume that the demand for electricity in each hour is completely independent of price, encourage customers to submit downward sloping demand schedules and offers to curtail load for some price. Experiments suggest that customers could wrestle some of the market power from generators by replacing the RTO.[25] Customers should be able to offer both reductions during peak demand and long-term reductions due to greater efficiency. Both serve to lower fuel costs, investment costs, and lower greenhouse gas emissions.

Sweeney [26] asserts that the problems in California in 2000 would have been solved, or at least been substantially less expensive, if there had been the ability to negotiate long-term contracts. Recently, Connecticut has followed this advice by asking for offers for up to 15 years in duration for new generation or demand side resources. The request appears to be successful in getting 33 offers for 6,000 MW of capacity. The offers include demand side activities as well as new generation. In particular, the project is designed to reduce "federally mandated congestion charges" and can include (1) customer-side distributed resources, (2) grid-side distribution resources, (3) new generation facilities, including expanded or repowered generation, and (4) contracts for a term of no more than fifteen years between a person and an electric distribution company for the purchase of electric capacity rights[27].

We expect that the offers will be at prices that owners expect to see in the hourly auctions. Aside from a bit of risk aversion, why would a generator sell for less than the price they expect to receive in the hourly auction? It would be socially efficient to offer consumers up to the expected market clearing price for demand side reductions. Connecticut could offer them less, but it makes no sense to forego a demand reduction that would save power at $60/MWh if the market clearing price is $65/MWh. Thus, we turn to a more radical proposal for altering the auction process.

<u>B. Monitor the auction markets closely</u> both at times of peak demand and other times to ensure that generators are being offered at marginal cost. PJM data suggest that market monitoring is not as stringent at hours of moderate demand as at times of peak demand. PJM's 2005 State of the Market Report shows that more units are offer-capped during the peak summer months than at other times of the year. Average price-cost markups in PJM are among the lowest in the summer months and at their highest in the winter.[28] If all offers at all times were scrutinized carefully, prices would fall.

This change is, at best, a short-term patch, since reducing current prices to variable cost would mean that many generators would not be able to recover their fixed costs. Giving incentives to generators to keep their plants operating and to invest in new capacity requires an additional payment, such as a capacity payment. We caution that relying so heavily on the market monitor would generate hostility, litigation, and might lead to generators leaving PJM if alternative transmission were available at a sufficiently low cost.

<u>C. Have Large Customers Face the Hourly Cost of Generating Electricity</u>**:** Most customers pay a fixed price for electricity rather than pay the current generation cost of electricity. This is not a new problem, but it has become a more important problem because generators are paid the market clearing price. Customers see a price that reflects the average annual cost of a kWh. At the hottest hour of the year, the market clearing price might be $1,000/MWh; at some times the market clearing price is zero. We doubt that customers would want to purchase as many kWh at $1.05/kWh as they would at $0.05/kWh (assuming transmission and delivery charges of 5 cents/kWh).

The history of charging a fixed price no matter what the generation cost has led to sharp demand peaks. For example, in PJM, 15% of the capacity is used only 1.1% of the hours. Under RORR, each plant was paid its unit cost. The average costs of the peaking plants were high, since they were used only a few hours each year, while the unit costs of the baseload plants were low. The weighted average cost of generating power over a year was less than in the restructured system where all generation is paid each hour's market clearing price. This means that the inexpensive baseload plants are paid the generation costs of the peakers during any hour when the peakers are used. In PJM, gas or oil fired plants set the market clearing price in some parts of the system during all or part of 85% of hours, leading to much higher payments to most generators.

Fixing the problem requires eliminating the highest levels of demand. For example, if the 98 hours requiring 15% of generating capacity could be managed so that the demand were shifted to other hours or other days, the savings would be considerable, especially when these peaking plants did not need to be replaced. In Pennsylvania, commercial and industrial customers represent 10% of the meters and consume 64% of the power.[29] If the large customers not on real time pricing (RTP) were put on it, we expect a large drop in the average electricity price. Furthermore, this shift would benefit all consumers, not just those who shifted, by lowering price in peak hours.

Spees and Lave[30] find that shifting only 7% of daily demand from peak to trough hours would realize 90% of the savings from leveling load. This amount of load shifting should be achieved by putting only the large customers on RTP. For Pennsylvania, perhaps 10% of customers represent 50% of the load. By focusing on 10% or less of the meters, the costs of RTP should be relatively low, making this approach cost-effective. Transferring demand to other hours would create a large benefit, the vast majority of which would accrue to the customers who have not taken any actions, since average prices would fall.

There is an equity-efficiency conflict here. Given the cost of advanced meters and resistance from getting some residential customers to sign up for RTP, it would be more efficient to focus on larger customers. However, not having all customers on RTP would subsidize those small customers whose peak demand occurred at the highest cost hours.

III. Fundamental Changes to the Market Design

A. Reregulation

As discussed in Part I, Virginia and Montana have reregulated and other states are studying the issue. The fundamental problem is what value to put on assets as they are pulled into the rate base.

B. Reregulating One Plant at a Time: An alternative would be to reregulate the system by having each new plant become part of a regulated system. One way to do this would be to have the LSE build and own each new plant. The PUC of each state could approve the new plants, putting their cost into the rate base. The LSE would receive a rate of return on their investments as well as their operating costs and the plants would be offered into the hourly power market. As the last old plant is retired, the new regulated utility would control the entire market and the hourly power auction would be abolished. While this is a simpler structure, it is regulation and does not represent a competitive market.

A variant on this process would be for the PUC or LSE to invite investors to offer for the right to construct a new plant, similar to the way that new capacity is offered in states like Georgia. This process would be different because each offer would specify a fixed and a generation cost of the new plant. The offers that were accepted would be paid the fixed cost each year, as long as the owners satisfied their contract obligations. They would be paid the generation cost for each MWh they were asked to generate power. This contract could put all of the risks on the generation owner, all on the rate payer, or share them in some way. If this market for new generators is competitive, it would have the virtues of a deregulated market. It would prevent the complacency that would come to any regulated entity whose costs were reimbursed with a fixed rate of return.

<u>C . Change the Auction Structure:</u> Competition does not require hourly markets. Instead of a single-price auction paying market clearing prices to all, change the structure to have each generator or demand side manager offer its fixed and variable cost for a contract of one year or longer.

We anticipate that current owners would be reluctant to offer their actual fixed and variable costs in this auction. This would be especially true for plants that have been extremely profitable, but even plants that had not been recovering their fixed costs would see an opportunity to earn high profits through offering prices above their actual fixed and variable costs. This structure would be appealing to generators in the sense that they would know that they would recover their costs, but they could not share in the high profits that come from the hours with price at $1,000 or more per MWh.

If the LSE found that plants were not offering their power or were offer prices higher than their actual costs, they could ask for a longer contract. In offering power into an hourly market, if a generator puts in too high an offer and is not selected, they lose their profit for that hour. Since there are 8759 more hours in the year, there is little cost to signaling other generators to submit high offers that raise everyone's profit. The computer simulations and experiments mentioned above show that generators were able to achieve market clearing prices higher than cost after only 40-100 hourly auctions. If the contract were for five years, a generator offering too high would lose five years of profit, a much higher penalty.

If, despite the penalty of not supplying power for a year or more, the LSE found that some generators were still offering power at a significant amount over their costs, lengthening the contract would put even more pressure on the generator to be competitive. However, a large generator that knew it was pivotal during some hours of the year could offer a high price, knowing that the PUC or LSE would have to buy the power for at least some hours.

If this occurred, the LSE could offer some "life of the plant" contracts. Adding new capacity to the market would mean that the existing capacity would be used less, lowering their profits. Thus, current generators would not want to see new capacity added, unless there is demand growth. If there were sufficient new generation plant sites available, we expect that there would be a competitive market for new generation. A life of plant contract with a credit-worthy entity would enable the winner to finance the new plant at favorable rates.

If the LSE wrote contracts with generators for all the power needed, there would be no need for an hourly auction market. The LSE or RTO would know the offers of each generator and could proceed with economic dispatch. If the LSE had contracts for only part of the generators, the RTO could continue to run the hourly auction market with the contracted plants offering power at their generation cost. Even if the contracted plants were less than the full capacity needed, they would help discipline the market.

Generators with high fixed and low variable costs, such as nuclear power plants and renewable resources, would discipline the market. Having paid the fixed costs of a nuclear, coal, or wind turbine, the generation costs would be so low that plants that had not contracted would not be able to compete. Thus, even if an existing coal generator had average costs lower than a new plant, the new plant would be more efficient (given the same level of air pollution and carbon dioxide control) and thus have a lower generation cost. If the old plant did not win the contract because they had offered too high a fixed cost, they would be unlikely to win in the power auction since their variable cost would be higher than the new plant. They would be dispatched only in the hours when demand was so high that the contracted plants could not supply the power. This means that an existing plant that offered overly large fixed costs would be used only a few hours each year, and probably would not cover these fixed costs.

The fixed cost component of the offer or contract acts as a capacity payment fixed for one year, multiple years, or the life of the plant. If the generator's offers were accepted and it adhered to the contract (maintained the availability and reliability levels), it would be paid its fixed costs. Rather than their having a uniform capacity payment for all generators, the fixed cost would be unique to each generator. When a plant was asked to generate electricity, it would be paid its variable generation cost for each MWh it generated.

In a highly competitive market, the market clearing prices for a long-term contract would be no greater than the fixed and variable costs of a new generator. The contract would have to specify the number of times each year a plant could be asked to start-up and the minimum run time. If there were a number of good sites for a new generation plant and the PUC or LSE assumed the risks in asking for "life of the plant" offers, a competitive market would provide offers at long-run average cost.

Under this plan, the RTO would know the fixed and variable costs of each generator under contract. Knowing demand, they could engage in economic dispatch just as they do today, and that utilities do or did under RORR. Plants would not be paid market clearing prices, but rather their generation cost. Since plants were paid their fixed and generation costs, the owners would earn their return on investment and be satisfied. Thus, the supply side of the market would receive competitive returns and there would be adequate incentives to add needed capacity. No generator would be over-paid, none would be under-paid and there would be no need for “band-aids” such as capacity markets.

The RTO would calculate LMPs so that it could charge RTP and allow customers to participate in demand side offers. The LMP would be the sum of the generating cost of the marginal generator and the congestion charge and a component for transmission losses. During periods of high demand, the LMP would be considerably higher than generation cost in load pockets; the LSE would receive payments higher than generation costs. Economic efficiency requires customers to pay RTP, the social cost of providing them each kWh, giving the PUC or LSE revenue considerably greater than its costs at high demand time in congested areas. During hours of low demand, the LMP would reflect the price paid to the highest cost supplier, generating revenue greater than the total payout to generators. The revenue above generating cost could be used to pay the fixed costs of the plants or for transmission.[31]

In some markets, the RTO would be paid more than the fixed costs of all plants while in others they would have to charge customers a monthly fee to pay for some of these fixed costs. The monthly fee would be a demand charge, based on usage during the peak demand hours. It would reflect the additional cost to the system of the capacity needed for each customer; this would be approximated by usage during the peak hours. For example, suppose that demand increased, requiring new capacity. If the fixed cost of this generation were $300/yr/kW, the demand charge would be $300/kW/yr. If this additional capacity were used for only one-hour per year, the customer would pay $300 plus the generation cost. If the additional capacity were used 8,760 hours per year, the demand charge would amount to 3.4 cents/kWh. This example illustrates how RTP provides a strong incentive to moderate peak demand.

If the revenue from RTP over a year exceeded the fixed cost plus generation cost payments, the surplus funds could be used to build new capacity, pay for demand-side reduction, be refunded to consumers with an annual check, or used to reduce taxes.

Generators under contract would be offered into the hourly auctions at their generation offer. The generators not under contract would submit their offers (under the watchful eye of the market monitor). As more generators came under contract, the pressure on the remaining generators to come under contract would increase. When all generators were under contract, the hourly auction would be abolished. Since each unit was paid its contract price, no unit would be over- or under-compensated (that is, no unit would be compensated based on the contract price of another unit).

This new market design is a competitive market design. The design is more likely to promote competitive behavior than the hourly auction market. In this design, the LSE would solicit offers for new plants and thus would be responsible for ensuring plants were built as part of a rational technology-fuel portfolio. The RTO would continue to perform economic dispatch, something that was managed by utilities in the past. Whether this system would be superior to the current one depends on the following:

1. What is the cost of new capacity? If new capacity is needed, its costs will influence market prices in either the current hourly power auction or the offers for a new plant. The owners of existing capacity benefit from the high prices of new capacity in a restructured market, but not under RORR.
2. There must be a number of attractive sites for new plants that do not engender public opposition. The sites have to be attractive in the sense of inexpensive land, easy access to cheap fuel, and easy access to transmission with sufficient capacity to carry the power.
3. There would have to be competition for the new plants, enough to force the offers to converge to the actual fixed and variable costs.

The capital cost of new coal and nuclear plants is considerably higher than that of plants built in the 1960 and 1970s. If the offers for existing plants went to the level of new plants, the retail prices would be considerably higher than costs in states that did not restructure. Costs under RORR would gradually catch up to those of restructured states as old plants were replaced. Compared to current prices in restructured states, these costs would be considerably less than the market clearing prices for long-term contracts. The fact that all plants would be paid their generation cost rather than the market clearing price would help lower costs.

NIMBY is real. Finding acceptable sites for new plants is not easy. The easiest sites are ones with existing power plants, which gives current generators an advantage, or even a monopoly, in offering to build new plants. To make this market design work, each state might have to acquire options to develop favorable sites and offer these to all aspirants. Inviting offers from companies to build a generator on a specified site open to all aspirants would promote competition.

Offering a site whose costs and other attributes is known to all aspirants, together with a life of plant contract, should promote intense competition. The competition would be open to all parties that thought that they could build the plant cheaper or operate it more cheaply that others. The competition would be akin to the bidding process for large construction projects with the added provision that the builder would operate the plant over its lifetime. Perhaps a builder and operator would get together to submit a joint offer to build and operate the plant.

<u>D. Other Contracting Issues:</u> In either model, a state could lower the cost of power by financing the plant with tax free industrial development bonds. A state could issue these bonds to the extent that they did not affect the state's broader borrowing power. Such an action on the part of the state would also transfer some risk from a utility's ratepayers to the state's taxpayers as a whole.

These contracts would be subject to various risks, as discussed above. A final difficulty is common to all new capital structures that are built: The owner is responsible for being able to operate the plant efficiently and reliably. Since there is nothing unique to an electricity generating plant, we presume that investors would not be put off by this risk.

IV. Recommendations

The assumption that hourly power auctions will be competitive is a fundamental flaw in current designs for deregulated markets. During peak demand, one or more generators are likely to be pivotal. More importantly, hourly actions have encouraged firms to bid strategically, increasing prices and profits. This conclusion is evident in the heavy-handed market monitors who are charged with forcing generators to offer when their capacity at their variable generating costs when it is needed.

One proposal is to go to long-term contracts for both generation and demand reduction. Each party would be paid their winning offer. If each plant offered power its average cost, this could lower price significantly. However, we doubt that generators would offer their power at prices lower than they expected to receive in the hourly auctions.

A second proposal is to give up on deregulation and return the system to regulation. The immediate difficulty in doing that is valuing the assets as they are put into the rate base. We predict that this would be contentious, except in the few restructured states that have not allowed LSEs to divest generators.

A third proposal is to regulate each new power plant that is built. Over several decades, this would reregulate the system. That is not a timely solution, since it would require the current level of scrutiny and market monitoring until the system was completely reregulated. We caution that RORR has its own problems.

Our recommended alternative is to solicit offers for long-term contracts that specified fixed and generating price for each plant. The PUC or LSE must be prepared to go to life of plant contracts in order to use the threat of new capacity to hold existing generators to competitive prices. The contracts would specify the number of times a generator could be asked to shut-down, as well as the availability and reliability of the unit. Complying units would be paid their fixed offer if they complied with the terms of the contract and their generation offer for each MWh they were asked to supply.

Customers would be charged real-time prices and, if needed, a demand charge based on their usage during periods of peak demand. This pricing structure would be efficient in an economic sense and would motivate customers to find ways to reduce their demand, especially at peak times.

In our judgment, this proposal would offer the benefits of competition, ensure that each generator was paid its reasonable costs and no more, and provide for the long-term operation of the system. Examples of how our proposal would work are available at www.cmu/electricity.

Appendix: Examples of the various market designs

Five market designs have been used or proposed for the US. To understand the implications of each, we have computed the price consumers will pay and profitability of three classes of generators under each design. The example uses data from PJM for 2006. The capacity of baseload, intermediate, and peaking generation, 55%, 12%, and 33% comes from PJM. We used the median price paid for each class of generation during the year, assuming that the market monitor made certain that price was similar to cost. Finally, the use of each generation class and its capacity factor comes from PJM data. The fixed costs for each class of generation are our estimates of these costs for new baseload, intermediate, and peak generators.

This analysis simplifies the actual market by neglecting the range of costs within each class of generator. For example, although the cost of baseload plants is assumed to be $33/MWh, actual plants ranged from less than $20/MWh to almost $50/MWh. The same is true for intermediate and peaking plants, although the range for peaking plants is much larger. Some peaking plants offer their power, and presumably have cost of, up to $300/MWh or more, depending on fuel prices.

We make a further simplification by assuming that there are three levels of demand. In the first, demand is just less than baseload capacity. The second demand level is just less than the sum of baseload and intermediate capacity. The third demand level is greater than the sum of baseload and intermediate capacity, and so requires the use of peaking capacity. We assume that there is no demand-side participation in the market and that demand is completely inelastic with respect to price; that is, the RTO or other system operator determines the demand in a given hour and schedules enough generation to serve all of that demand (with the usual caveats for real-time adjustments).

We consider the following market designs:

I. The first market design is a free market for generation with no market monitors, but with a hard price cap of $1,000/MWh. We assume that generators will learn to offer the baseload plants at $998/MWh, their intermediate plants at $999/MWh, and their peakers at $1,000/MWh.

II. The second market design is similar to the first, but we assume that the market monitor enforces all plants offering power at their marginal cost.

III. The third market design has the market monitor forcing plants to be offer power at MC, but with no obligation to offer their generators. Plants could be withheld if that is profitable.

IV. The fourth market design assumes that all plants will agree to long-term contracts that specify their true fixed and marginal costs.

V. The final market design is the classical RORR with the plants being reimbursed for their fixed and marginal costs. However, their costs are assumed to be higher than under the competitive designs since there was little incentive to slash costs.

Market Design I: In the first market design, the baseload, intermediate, and peaking plants are offered at $998, $999, and $1,000 respectively in all demand conditions. If so, in the first demand condition, the market clearing price is $998/MWh and the variable profit, revenue minus marginal cost, is $965/MWh for baseload plants. Neither the intermediate nor peaking plants sell any electricity. When the demand is at level two, the market clearing price is $999/MWh and the baseload plants earn $966/MWh more than MC and the intermediate generators earn $947/MWh more than their MC. At demand level 3, all the capacity is being used, the market clearing price is $1,000 and the baseload plants earn $967/MWh, the intermediate plants earn $948/MWh, and the peakers earn $919/MWh.

In PJM in 2006, the first demand level occurred 4,730 hours, the second demand level occurred 1,840 hours, and the highest demand level occurred 2,190 hours. Under the assumptions of the first market design, a baseload plant would earn $8,460,223 more than its MC, the intermediate plant would earn $3,735,965 more than its MC, and the peaker would earn $2,656,829 more than its MC. All three plants would be able to repay their fixed costs of $300,000/MW-y, $200,000/MW-y, and $100,000/MW-y, respectively. As the market in California in 2000 illustrated, once the generators learned to offer prices above their MC, they became enormously profitable.

Unsurprisingly, generators do very well when their offers can reflect the price cap rather than costs.

Market Design II: Baseload makes $19 for 1,840 hours and $48 for 2,190 hours for a total of $140,080. But since FC = $300,000, the plant incurs a loss of $159,920 each year.

Intermediate makes $29 for 2,190 hours for a total of $63,510. But FC = $200,000 and so the plant incurs a loss of $136,490.

The peaker is never paid above MC and so incurs the full loss of its FC = $100,000.

Market Design III: Baseload makes $48 for 1,840 hours and $48 for 2,190 hours for a total of $193,440. Since FC = $300,000, the plant incurs a loss of $106,550.

Intermediate makes $29 for 2,190 hours for a total of $63,510. But FC = $200,000 and so the plant incurs a loss of $136,490.

The peaker is never paid above MC and so incurs the full loss of its FC = $100,000.

Market Design IV: Each generator is paid only its MC for generation and is paid their FC when their offer is accepted. The total cost is $728,235.

Under Market Design I, when generators can offer and arrive at the price cap, all types of generators cover their FC and make large profits.

Under Market Design II, when generators are forced to offer at MC and there is no withholding, each type of generator fails to cover its FC. If there were a competitive capacity market, the market clearing price would be offered by the baseload plants at $159.92 per kW. This market clearing price would overcompensate the intermediate and peaker plants by $23.43/kW and $59.92/kW respectively. This market design is problematic since it over-compensates the intermediate and peaker units by a total of $83,350.

Under Market Design III, being able to withhold the intermediate plant adds to the amount over MC that the baseload plant is able to earn, but all plants still fail to cover their FC. The market clearing price in a capacity auction would be the $136.49/kW, offered by the intermediate plant. This would over-compensate the baseload and peaker plants by $29.93/kW and $36.49/kW, respectively. This design over-compensates the baseload and peaker units by a total of $66,420.

Under Market Design IV, all plants are paid their costs and no more. The total cost is the same as the total revenue: $1,276,030. **or 728,235 - check

Although prices have not fallen under restructuring, costs have. The work force has been reduced and the availability of plants has been increased. Market Design I would not be tolerated for long, as California showed. Market Design II overpays generators $83,350 or 6.5%. Market Design III overpays generators $66,420 or 5.2%. Thus, if competition brought less than a 6.5% or 5.2% decrease in costs due to greater efficiency, the RORR market design would have been more efficient. However, assuming that generators would offer their true FC and MC on long-term contracts, market design IV would be the lowest cost design.

This example makes an enormous simplifying assumption: A single peaker, single intermediate, and single baseload plant. If there were two baseloads, one at $20 and one at $40, two intermediates at $50 and $70, and two peakers at $80 and $300, the outcome of the analysis would be quite different. In Market Designs II and III, the cheaper baseload plant would be profitable. Depending on how many hours, the market clearing price was $300, all other plants including the other peaker could be profitable. In PJM, the range of baseload plants, intermediates, and peaking plants makes the lowest cost baseload plants profitable, as well as some other plants. The highest cost peaking plant cannot earn its FC under Market Designs II and III and so there must be a capacity market that will almost certainly over-compensate most plants.

Table: Example of 4 Market Designs

Baseload: FC = $300/kW-yr, or $300,000/MW-y MC = $33/MWh Capacity: 55%
Intermediate: FC = $200/kW-yr, or $200,000/MW-y MC = $52/MWh Capacity: 12%

Peak FC = \$100/kW-yr, or \$100,000/MW-y MC = \$ 81/MWh Capacity: 33%

The prices represent PJM data for 2006 and are assumed to reflect MC. The fixed costs are for new generators without CCS. D_1 assumes that demand is in baseload range, D_2 assumes demand is in intermediate range, D_3 assumes demand is in peaker range.

I. Free market, price cap of \$1,000/MWh: Offer \$998 for baseload, \$999 for intermediate, and \$1,000 for peakers. The price paid to all generators is \$998/MWh for D_1, \$999 for D_2 & \$1,000 for D_3. Variable profit, revenue minus MC, is shown below for baseload, intermediate, and peakers, respectively. In the following tables we will let $V\Pi_B$ represent variable profit for baseload generation, in \$/MWh, while $V\Pi_I$ and $V\Pi_P$ represent variable profit for intermediate and peaking generation. We also assume that D_1 occurs 4,730 h/yr, D_2 occurs 1,840 h/yr, and D3 occurs 2,190/yr

For D_1 = 55, $V\Pi_B$ = \$998 – 33 = \$965/MWh; $V\Pi_I$ and $V\Pi_P$ are zero.
For D_2 = 65, $V\Pi_B$ = \$966/MWh; $V\Pi_I$ = \$999 – 52 = \$947/MWh; $V\Pi_P$ = zero.
For D_3 = 100, $V\Pi_B$ = \$966/MWh; $V\Pi_I$ = \$948/MWh; $V\Pi_P$ =\$1,000 – 81 = 919\$/MWh.

II. Free market, market monitors compel offers at MC with no withholding.
For $D_1 < 55$, Price = \$33/MWh and no generator earns variable profit.
For $55 < D_2 < 67$, Price = \$52/MWh and $V\Pi_B$ = \$19/MWh. Intermediate and peaking plants earn no variable profit.
For $D_3 > 67$, Price = \$81 and $V\Pi_B$ = \$48/MWh; $V\Pi_I$ = \$29/MWh; and the peaking unit earns no variable profit.

III. Free market, market monitors compel offers at MC, but withholding is possible.
For $D_1 < 55$, Price = \$33/MWh and no generator earns variable profit. For $55 < D_2 < 81$, Price = \$81/MWh and $V\Pi_B$ = \$48/MWh. Intermediate and peaking plants earn no variable profit.
For $D_3 > 67$, Price = \$81/MWh and $V\Pi_B$ = \$48; $V\Pi_I$ = \$29/MWh. The peaking unit earns no variable profit.

IV. Long-term contracts with a two-part tariff specifying fixed and variable costs.
For $D_1 < 55$, Price = \$33/MWh and no generator earns variable profit.
For $55 < D_2 < 81$, Price = \$52/MWh and no generator earns variable profit.
For $D_3 > 67$, Price = \$81/MWh and no generator earns variable profit.

Glossary:

RORR Rate of Return Regulation
kW 1,000 watts of electrical capacity
kWh 1,000 watts of electricity delivered for 1 hour
MW Megawatts (1 million watts)
MWh A MW of power for one hour
T&D Transmission and Distribution
PUC Public Utility Commission
R&D Research and Development
FERC Federal Energy Regulatory Commission
ISO Independent Systems Operator
RTO Regional Transmission Organization
CAISO California ISO
PJM The RTO for the Mid-Atlantic region
NYISO New York ISO
ISONE ISO New England
MISO Midwest ISO
LSE Load Serving Entity (the owner of distribution lines)
ERO Electric Reliability Organization
NERC North American Electricity Reliability Corporation
LMP Locational Marginal Pricing

Endnotes:

[1] FERC v. Mississippi, 456 U.S. 742.

[2] These studies include Apt, J., Competition Has Not Lowered US Industrial Electricity Prices. The Electricity Journal, 2005. **18**(2) at 52-61; Cambridge Energy Research Associates, Beyond the Crossroads, the Future Direction of Power Industry Restructuring. 2005; Center for the Advancement of Energy Markets, Estimating the Benefits of Restructuring Electricity markets: An Application in the PJM Region. 2003. Available at http://www.caem.org/website/pdf/PJM.pdf; Energy Security Analysis, Inc., Impacts of the PJM RTO Market Expansion. 2005. Available at http://www.pjm.com/documents/downloads/reports/20051101-impact-pjm-expansion.pdf; Fagan, M. Measuring and Explaining Electricity Price Changes in Restructured States. The Electricity Journal, 2006. **19**(5) at 35-42; Global Energy Decisions, Putting Competitive Power Markets to the Test: The Benefits of Competition in American's Electric Grid. 2005. Available at http://www.globalenergy.com/competitivepower/competitivepower.pdf; ISO/RTO Council, The Value of Independent Regional Grid Operators. 2005. Available at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/Value_of_Independent_Regional_Grid_Operators.pdf; Joskow, P., Markets for Power in the United States: An Interim Assessment, The Energy Journal. 2006. **27**(1) at 1-36; Synapse Energy Economics, Electricity Prices in PJM: A comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs. 2004. Available at http://www.pjm.com/documents/downloads/reports/synapse-report-pjm-electricity-prices.pdf; Taber, J., Chapman, D. and Mount, T., Examining the Effects of Deregulation on Retail Electricity Prices. Cornell University Department of Applied Economics and Management Working Paper Wp 2005-14. 2006. Available at http://aem.cornell.edu/research/researchpdf/wp0514.pdf; Weaver, J.L., *Can Energy Markets Be Trusted? The Effect of the Rise and Fall of Enron on Energy markets*. 2004. Houston Business and Tax Law Journal (4) at 1. Available at http://www.hbtlj.org/v04/v04Weaverar.pdf.

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[5] Kwoka, J. *Restructuring the U.S. Electric Power Sector: A Review of Recent Studies*. 2006. Available at http://www.appanet.org/files/PDFs/RestructuringStudyKwoka1.pdf.

[6] Rose, K. and Meeusen, K., *2006 Performance Review of Electric Power Markets Part I: Status of the Development of Regional Competitive Markets: Performance Review of Electric Power Markets*. Virginia State Corporation Commission. 2006. Available at http://www.scc.virginia.gov/caseinfo/reports/2006_rose_1.pdf.

[7] See Section 3 of Apt, J., S. Blumsack, and L.B. Lave, *Competitive Energy Options for Pennsylvania*. 2007, Team Pennsylvania Foundation: Harrisburg. 95 pp. Available at http://wpweb2k.gsia.cmu.edu/ceic/pdfs_other/Competitive_Energy_Options_for_Pennsylvania.pdf.

[8] Rose, K. *The Impact of Fuel Costs on Electric Power Prices*. 2007. Available at https://www.appanet.org/files/PDFs/ImpactofFuelCostsonElectricPowerPrices.pdf.

[9] Apt, *supra* note 2.

[10] Taber, et al., *supra* note 2.

[11] Bateman and Smith, *supra* note 3.

[12] See Blumsack, S. and L.B. Lave, "Mitigating Market Power in Restructured U.S. Electricity Markets," *Papers and Proceedings of the 24th North American Conference*, U.S. Association for Energy Economics, July 2004; and Zhang, F., 2007. "Does Electricity Restructuring Work? Evidence from the U.S. Nuclear Energy Industry," *Journal of Industrial Economics*, forthcoming.

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[14] Bodmer, *supra* note 3.

[15] Bodmer, *supra* note 3.

[16] Natural gas is on the margin in all or part of 85% of the hours in some areas of the PJM system. See Apt et al., *supra* note 6, Section 3.

[17] The one possible exception is California, which halted its restructuring program following the power crisis and the bankruptcy of its principal market-maker, the California Power Exchange. California is currently in the process of instituting a new electricity market similar to those in PJM and other Eastern RTOs.

[18] PJM 2005 State of the Market Report, Section 2, available at http://www.pjm.com/markets.market-monitor/som/html.

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[21] See "Green Mountain Power Alternative Regulation Plan," under Vermont PSB Dockets 7175 and 7176, available at http://www.gmpvt.com/atyourservice/2006ratefiling.shtml.

[22] FERC also has the authority to provide "incentive rates" to encourage transmission investment.

[23] Energy Policy Act of 2005, Sec. 1221.

[24] Rose, *supra* note 7.

[25] Talukdar et al., *supra* note 18, Adilov et al., Taber et al., *supra* note 19, and Rassenti, S., V. Smith and B. Wilson, 2003. "Controlling Market Power an Price Spikes in Electricity Networks: Demand-Side Bidding," *Proceedings of the National Academy of Sciences,* 100:5, at 2998 – 3003.

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[27] State of Connecticut, Department of Public Utility Control Docket No. 05-07-14 PHOZ Draft Decision, April 23, 2007.

[28] PJM 2005 State of the Market Report, *supra* note 17.

[29] Apt, et al., *supra* note 6, Section 4.

[30] Spees, K. and L.B. Lave, 2007. "Impacts of Responsive Load in PJM: Load Shifting and Real Time Pricing," Carnegie Mellon Electricity Industry Center working paper CEIC-07-02.

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