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Working Paper

Electricity Restructuring: What Has Worked, What Has Not, and What is Next

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**ECONOMIC ANALYSIS GROUP
DISCUSSION PAPER**

**Electricity Restructuring: What Has Worked,
What Has Not, and What is Next**

by

Jeff Lien *
EAG 08-4 April 2008

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Abstract

In the 1990s and early 2000s, a series of state and federal initiatives restructured electric markets. In many areas of the country generation was unbundled from transmission and distribution and competitive markets for energy generation were established. A decade has now passed since many of these market reforms were implemented, and increasing energy prices have re-focused attention on these reforms. In particular, commentators are blaming the reforms for the rising energy prices and, in several states, legislators are now considering re-imposing regulation. In this paper I discuss some successful features of industry restructuring, and consider areas where further reform may be warranted. It appears that market restructuring is now producing significant tangible benefits in the areas of the country where it has been most fully implemented. Calls for the reimposition of heavy-handed regulation should be resisted.

1. Introduction and Overview

Throughout most of the 20th century, electricity in the U.S. was commonly supplied by vertically integrated regulated utilities controlling the generation (power plants), transmission (high voltage power lines) and distribution (lower voltage lines) of power in well-defined service territories. Through cost of service regulation, state regulators set retail rates that ensured that utilities could cover their operating and capital costs. In the 1990s, consumers became increasingly dissatisfied with regulated prices as the high capital costs of nuclear and other investments in prior decades continued to be reflected in rates, while innovative generating technologies and low natural gas prices made potential alternative sources seem very attractive. Furthermore, the experience from the deregulation of other industries, such as airlines and trucking, suggested that profit motives could lead to more efficient operations and investment and that price competition could ensure that these efficiency improvements were passed on to consumers.

Starting in the mid-1990s, a series of state and federal initiatives restructured electricity markets. Reforms focused on the observation that while transmission and distribution systems continue to exhibit many of the features of a natural monopoly, the efficient scale of a power plant is now sufficiently small so as to allow effective competition among generators. As described in Section 2, market restructuring involved the divestiture of generation from utilities, the formation of organized wholesale spot energy markets with non-discriminatory economic mechanisms for the rationing of scarce transmission resources, the introduction of retail choice programs, and the establishment of new forms of market oversight and coordination.

Ten years later, many commentators paint a very gloomy picture of the status of the restructuring of the electric industry.¹ They point to rising energy prices. They single out the exercise of market power by generation companies in deregulated markets and its key contributing role to the California energy crisis. They decry, in the face of rising energy prices for customers, the large profits that have accrued to some energy providers, such as nuclear generation plants. They highlight that competition for residential customers has not materialized in states that have allowed customer choice. In fact, across states that restructured their electric industry, legislators and policy-makers are facing calls for, and in some cases actively considering, re-imposing cost of service regulation.

In this paper, I highlight that there is substantial evidence that significant efficiencies have been achieved by market restructuring, especially through improved incentives for plant-level

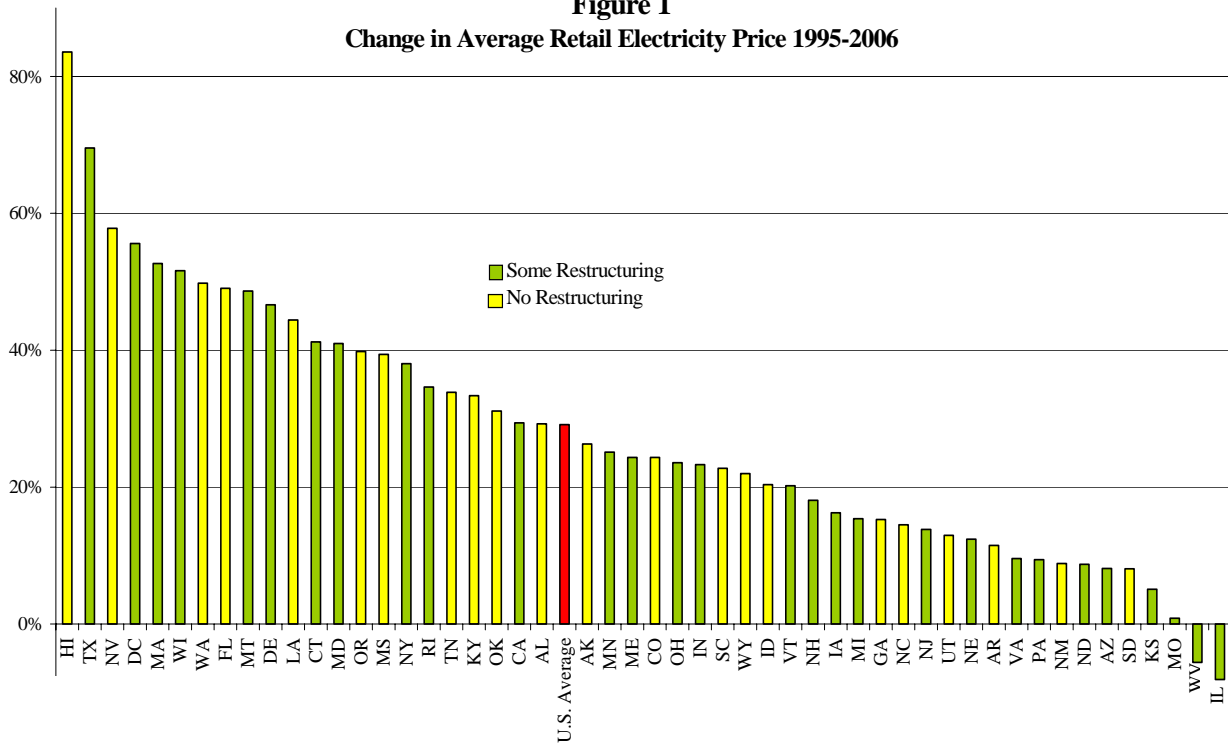
¹ See “Competitively Priced Electricity Costs More, Studies Show,” David Cay Johnston, New York Times, November 6, 2007; “Electricity Deregulation: High Cost, Unmet Promises,” Terence O’Hara and Amit R. Paley, Washington Post, March 12, 2006; Comments of the American Public Power Association pursuant to FERC Docket Nos. RM07-19-000 and AD07-7-000, as corrected September 24, 2007.

operating efficiencies and improved mechanisms for eliciting gains from trade in wholesale trading. However, not all potential benefits of restructuring have been realized, and there is the possibility of further development of market designs. Increased exposure of consumers to wholesale spot prices, more effective coordination of transmission investment, and the improvement of market designs that discourage market power while maintaining incentives to invest in generation are key for the long-term development of efficient electric markets and lower consumer prices. As regulators consider market reforms, they should look towards the development of these aspects of the competitive marketplace, not towards a return to cost of service regulation.

The evidence simply does not support critics' claims that there have been dramatic price increases in restructured states relative to states that have maintained more traditional forms of regulation. As Figure 1 demonstrates, there is no clear pattern in the restructuring status of the states that have seen the greatest increases in retail prices since the mid-1990s.² Among the 28 states in which some form of restructuring was implemented, 10 (plus the District of Columbia) experienced increases in average retail prices from 1995 to 2006 that outpaced the national average and 18 states had increases (or even decreases) below the national average. Among the non-restructured states, 11 had price increases above the national average and 11 had below average price increases.

² As discussed in Section 2, restructuring applied to many different facets of the industry and varied considerably across states and regions. The partition of states into restructured and not-restructured categories is not clear cut. For the purposes of Figure 1, I define "Some Restructuring" rather broadly to include states that have had significant changes in wholesale and/or retail markets.

Figure 1
Change in Average Retail Electricity Price 1995-2006

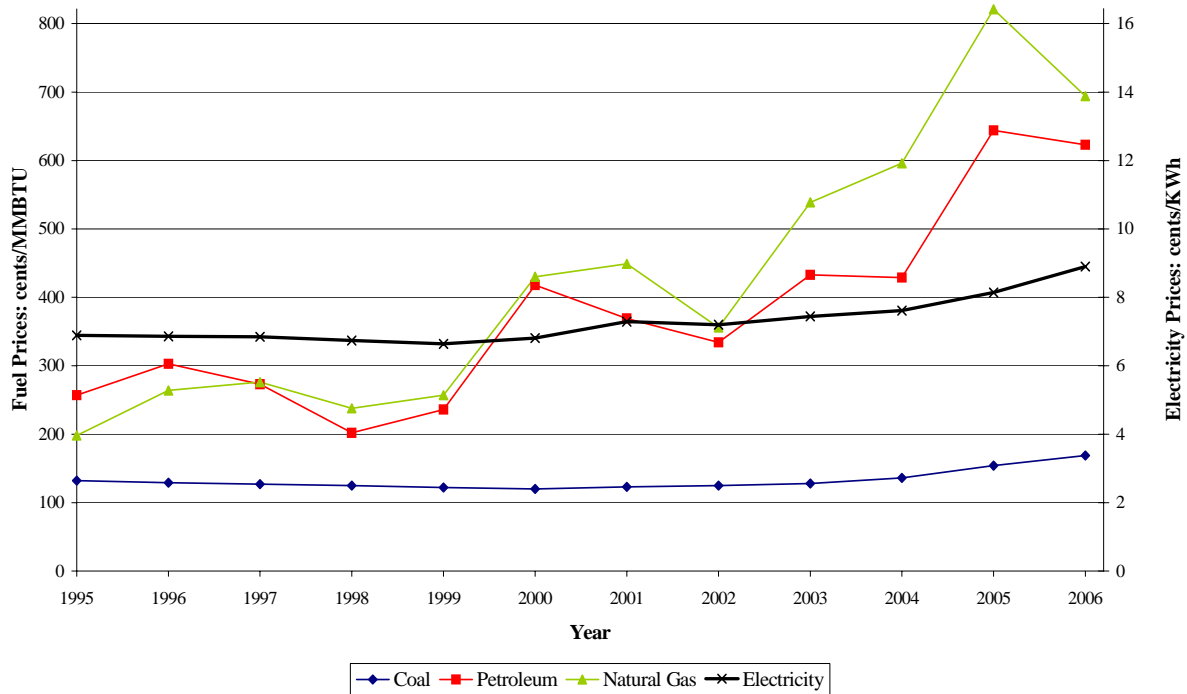


— Prices Source: EIA

Note: A state is considered to have experienced some restructuring if there is either significant RTO participation or customer choice

Simple comparisons as in Figure 1 are generally insufficient to answer questions of causation. Many factors other than restructuring can influence retail electricity prices in a given state. In particular, electricity is generated from various fuels, mostly coal, nuclear, natural gas and petroleum. There is clear evidence that increases in fuel prices are responsible for much of the increase in electric rates. As demonstrated in Figure 2, from 1995-2006, coal prices increased by 29%, the prices of petroleum products used at power plants increased by 121%, and natural gas prices increased by 188%. Over the same time period, nationwide average electric prices increased by only 29%. Much of the pricing variation depicted in Figure 1 is explained by the fact that there is a different mix of fuel-types in the electric generating portfolio of each region. Variation in demand growth can also explain some of the divergence in rate increases.

Figure 2
National Average Fuel and Retail Electricity Prices



In recent years, analysts have relied on statistical modeling to go beyond the naive question of “did price go up?” to the more focused and appropriate question of “did restructuring *cause* prices to go up?”³ Studies suggest that overall, consumers have benefitted from industry restructuring. Joskow (2006) uses state-level data from 1970-2003 and finds that the presence of retail competition and competitive wholesale alternatives tends to decrease price, with a total price effect of perhaps 5-10%. Harvey, McConihe and Pope (2007) use annual average rates for municipal and cooperative utilities for the 1990-2004 time period and find that restructuring in the mid-Atlantic and New York produced benefits in the range of \$.50 to \$1.80/MWh equivalent to a total of \$430 million to \$1.3 billion per year. Other papers showing price reductions in restructured markets include those by the Center for the Advancement of Energy Markets (2003), Cambridge Energy Research Associates (2005) (claiming \$34 billion in consumer savings from restructuring over 7 years), and Fagan

³ To improve the reliability of their predictions, the best studies also use econometric techniques to directly control for other factors that might influence price, like fuel prices, generation type and measures of region-specific demand determinants (e.g. climate).

(2006).⁴ All of these studies are in agreement that rising fuel costs are largely responsible for recent increases in electricity prices.

However, it should be noted that a consideration of restructuring's effect on prices should not constitute the entirety of an assessment of the success of restructuring. The goal of market restructuring should be to create an environment that encourages operational efficiencies and economically justified investment decisions while limiting market power, the cost of implementing competition and any adverse impact on reliability (or perhaps even putting in place reliability improvements). If that kind of environment can be fostered, then consumers will benefit from restructuring in the long run. It is often very difficult to draw definitive direct conclusions regarding restructuring's overall effect on long run equilibrium pricing from a snapshot of pricing data (even a "snapshot" containing 10 years of history), and it is therefore necessary for market analysts to look directly and narrowly at the impact that restructuring has had on the market forces that affect prices and that will continue to affect them in the long run.⁵ In doing so we can evaluate which elements of restructuring have been a success and which elements deserve further consideration. Analysts have found significant benefits from restructuring in at least two areas that ultimately have an important impact on market prices: plant-level operating efficiency and the effectiveness of new trading arrangements in eliciting gains from trade.

Under cost-of-service regulation, a utility could only achieve temporary benefit from operating cost savings – at the time of the next rate hearing, rates would be lowered to reflect the improved cost structure. This limits incentive for cost minimization, thereby keeping prices higher than they might be in a fully optimized world. There is now substantial evidence that, in states that have restructured, generating firms have lowered their costs and improved their operating

⁴ Some pricing studies including those by Taber, Chapman and Mount (2006) and Apt (2005) do not find benefits from restructuring. Kwoka (2006) criticizes these studies to the extent that they focus on rate of price change rather than price levels, and to the extent that their designations regarding if and when states restructured are overly simplified or misstated.

⁵ Typically, comparative pricing studies do not attempt to demonstrate that the prices that have resulted in restructured states constitute long run competitive equilibrium prices. As discussed in Section 3, the period from 2000 to 2004 saw a boom in investment in generating capacity. In hindsight it appears that at least some of the investments were made pursuant to overly optimistic forecasts as margins in many restructured areas fell in subsequent years to levels that generally did not support further investments. The observed low prices could be a temporary aberration of the boom/bust cycle of investment rather than an indication of the long-term prospects of sustained success. Given continuous uncertainty in the profitability of investment, the concept of "long run equilibrium" is essentially a theoretical construct, not a destination that will be reached and held at some point in the future. The interpretation of many pricing studies is further complicated by the transitional pricing mechanisms introduced by regulators at the time of restructuring. See Kwoka (2006) for an overview and critique of studies on the net benefits of restructuring.

performance. Bushnell and Wolfram (2006) estimate plant-level efficiency improvements (as measured by heat rates) of approximately 2%. Fabrizio, Rose and Wolfram (2006) find a reduction in labor and operating costs of 3 to 5%. Shanefelter (2006) finds that merchant generators are able to save 30% or more on payroll expenses, relative to utility generators, without cutting wage rates. In each of the above studies, the authors attribute the efficiency enhancements to the improved incentive mechanisms inherent in restructured markets. Greater efficiency and lower costs enhance total economic welfare, provide investment incentives and save on scarce input resources. Ultimately, retail competition or other mechanisms (discussed in Section 3) can ensure that cost savings are passed through to consumers in the form of lower prices.

In addition to improvements in *how* plants are used, there have been improvements in *when* plants are used. While in many areas of the country utilities continued to own their transmission lines, some of the authority for determining access to them has been turned over to a regional non-profit Independent System Operator (ISO).⁶ ISOs run spot market auctions that determine the efficient scheduling and dispatch of generating facilities. ISO markets produce spot prices that more clearly reflect the cost and value of consumption and production than the pricing mechanisms that existed prior to restructuring. ISO pricing and dispatch generally ensure that when the transmission network allows it, lower cost generators will run before higher cost generators. Furthermore, ISO markets creates mechanisms that efficiently allocate scarce transmission capacity when transmission constraints arise. Global Energy Decisions (2005) studied the efficiencies that were gained when the ISO of the mid-Atlantic area, PJM, broadened its territory into areas of the Midwest. Using a model of the transmission network, they found that the efficiency of the usage of transmission “seams” between PJM and the Midwest was significantly enhanced as those seams were internalized into PJM’s integrated market mechanisms, producing total cost savings of \$85.4 million in 2004. This result is indicative of the benefit of spot market formation and greater trading efficiency – prior to the formation of ISOs, virtually all trading between utilities was done over inefficiently utilized seams, resulting in higher costs of production in the aggregate.⁷

To summarize, there is substantial evidence that significant benefits have been achieved by market restructuring. The introduction of profit incentives has resulted in more effective plant operations. The diversity of market participants looking for profitable trading opportunities has allowed the creation of sophisticated and efficient wholesale markets. Moreover, there is evidence

⁶ As in FERC’s Standard Market Design initiative of 2002, the terminology “Regional Transmission Organization” is often used in place of “Independent System Operator.”

⁷ Studies commissioned by PJM (Energy Security Analysis, 2005) and the New York ISO (Analysis Group, 2007) find hundreds of millions of dollars of cost savings from the expansion of PJM and the formation of the New York ISO, and attribute much of the savings to more effective trading mechanisms.

that prices are lower relative to what they would have been in the absence of restructuring, and reason to believe that beneficial pricing effects will continue for the long run. This is not to say that some degree of regulatory oversight and control of electricity markets is not warranted for several legitimate reasons. These include the susceptibility of energy markets to market power, significant challenges to the development of large interregional transmission capacity projects, and difficulties in exposing residential customers to wholesale prices. As I explain in the remainder of the paper, policymakers should focus their attention toward perfecting the mechanisms that are used to address these challenging features of electricity markets, not toward radical reversals of restructuring efforts. Calls for heavy-handed reimposition of regulation should be resisted.

2. The Elements of Restructuring

In the late 20th century, technical innovation lowered the cost of long distance power transmission and created new gas-fired generating technologies that were low cost relative to the rates charged by many regulated utilities. Consumers, particularly industrial customers, became dissatisfied with regulated prices and pushed for industry restructuring believing that if they could choose to buy from alternative sources, the prices that they paid would fall significantly. It was also observed that if a competitive generation sector developed there would be opportunities to develop more liquid wholesale markets with improved and transparent pricing mechanisms, allowing for more efficient trading across greater distances. Starting in the mid-1990s, a series of state and federal initiative restructured electricity markets.

Defining restructuring is not straight-forward as restructuring applied to many different facets of the industry and varied considerably across states and regions. In what follows below I discuss the most common elements of market restructuring. The reforms discussed below applied to only a subset of the country. Some areas, including much of the Southeast and West, continue to operate under more traditional regulation.

Structural separation

Generation was unbundled from regulated utilities, which continued to operate their transmission and distribution systems under cost of service regulation. In some cases (e.g. much of Pennsylvania) generation was sold or transferred to an affiliate of the utility and a “firewall” was established between regulated and unregulated affiliates. In other cases (e.g. much of California) the generation was sold off to “merchant” generating companies. Between 1998 and 2002, there was

a change in the ownership of approximately 20% of U.S. generating capacity. By 2006, approximately 40% of generating capacity in the U.S. was owned by non-utility generators.⁸

Wholesale markets

In many areas of the country, utilities continued to own their transmission lines, but turned some of the authority for determining access to them over to a regional non-profit Independent System Operator (ISO).⁹ Because the flow of electricity follows the laws of physics, not direct routing instructions, electricity system operators prevent overloading of transmission lines indirectly through generation – the output levels of generating plants must be monitored and adjusted if necessary to keep transmission flows within acceptable tolerances. ISOs indirect management of transmission flows comes in the form of spot market auctions that they run to determine the scheduling and dispatch of generating facilities. The ISO spot markets are designed to give generation suppliers non-discriminatory open access to transmission, to make the transmission pricing of wholesale transactions cost justified, and to economically manage the rationing of scarce transmission capacity across a pool of many utility systems.

There has been a great degree of variance in the form of wholesale spot markets, with some convergence toward a consensus format over time. The typical wholesale spot market now includes an auction in which generators submit offers to supply, specifying how much they are willing to produce at various price levels as well as various operating characteristics like minimum-run times. Generators are then dispatched in a way that meets total demand while minimizing as-offered costs and respecting transmission and other operating constraints. Wholesale prices are determined at each node of the transmission grid as the marginal cost of supplying one more unit of power to the node. When transmission congestion arises, prices diverge across the network with lower prices paid in areas where additional generation would tend to exacerbate congestion and higher prices arising where additional generation would tend to relieve congestion. This “nodal pricing” market design, which has been used for a decade in areas of the Northeast, was recently adopted by the markets in California and Texas.¹⁰ As of 2008, a majority of electricity in the country will be sold or scheduled through nodal price auctions.

Retail competition

⁸ EIA (2007)

⁹ As in FERC’s Standard Market Design initiative of 2002, the terminology “Regional Transmission Organization” is often used in place of “Independent System Operator.”

¹⁰ California and Texas had previously used market designs where congestions costs were aggregated across zones producing less reliable and transparent pricing signals.

Through various state initiatives, retail rates were unbundled and retail customers were given the opportunity to turn to a competitive retailer to provide the power (not including distribution) portion of their supply. Retailers acquire power for their customers either by producing it out of their own power plants or by buying it in wholesale markets. Distribution utilities continue to deliver power in their historically defined service territories and are obligated to provide non-discriminatory distribution service at regulated rates. There is significant variation across states in the extent of retail competition allowed. Currently, 16 states and the District of Columbia allow some level of customer choice.¹¹

Continuing oversight

It should be noted that very few of these restructuring steps involve complete “deregulation.” The efficient scale of generation is small enough so that the generation sector is generally not a natural monopoly and a form of competitive market structure is feasible. However, as discussed further below, there remain many characteristics of the electric industry that continue to make some level of regulatory oversight and control necessary.

3. Restructuring’s Effects on Operations, Trading and Investment

Clear Benefit: Plant-level Operating Efficiencies

As stated earlier, econometric studies provide significant statistical evidence that restructuring has encouraged firms to improve their operating performance (see Bushnell and Wolfram (2006), Fabrizio, Rose and Wolfram (2006), Shanefelter (2006)). These studies attribute the efficiency enhancements to the improved incentive mechanisms inherent in restructured markets. Under cost of service regulation, the utilities’ motivation to achieve operating efficiencies were limited; in time, regulators would adjust rates down to reflect the utilities’ cost savings. In a competitive environment, prices fall as *market-wide* cost savings are achieved and passed through; however, any *individual* generator’s cost savings will have a relatively small impact on market-wide pricing. Therefore, generators have a continuing incentive to operate as efficiently as possible in order to meet or beat the cost structure of the competition. The evidence seems clear that allowing generators an unfettered profit motive to achieve cost reductions and operational improvements

¹¹ By 2000, 24 states had enacted legislation allowing for retail competition. Since the California energy crisis and Enron scandal of 2000-2001 there has been a retreat from retail competition. Some states never implemented their competition legislation, whereas other states limited the classes of customers for which restructuring applied or suspended competition entirely. See The Electric Energy Market Competition Task Force Report (2007) for a state by state history of consumer choice.

enhances the efficiency of plant operations.¹² These cost reductions may be passed through to consumers and may also increase the profitability of plant operations. Increased profitability should not be feared as it is part of any total welfare calculation and provides incentive for investments needed to ensure competitive market outcomes in the future.

Clear Benefit: Efficiency of Trading

To the extent that wholesale markets existed under regulation, they were generally used for the trading of “excess energy” – if a utility had more generation than it needed to supply its customer base it might trade with a neighboring utility that was looking to make up a generation deficiency. Long-distance energy trading was uncommon as it could be costly to obtain transmission rights that crossed multiple delivery systems. Wholesale transmission pricing generally had little relationship to marginal economic costs, and the regulatory systems governing transmission rationing in times of scarcity did little to address cost minimization across utilities. In that regard, the transparency of pricing under the ISO systems has marked a major improvement over the pricing mechanisms that existed prior to the mid-1990s and promotes efficient trading among market participants. Centralized auction-based markets generally cause generation to be turned on and off in order of cost as demand ramps up and down. The markets effectively allow for region-wide optimization of generation dispatch in a way that was previously possible only on a utility by utility basis. This has significantly increased efficiency in dispatch and trading. More efficiency and lower costs ultimately mean lower wholesale spot prices for electricity. And, as I subsequently discuss, increased exposure of consumers to wholesale spot prices could produce lower retail prices, to the benefit of consumers.

The success of ISO systems comes from carefully coordinated market design, not free-for-all deregulation. Given the significant externalities in transmission, market conditions that change minute by minute, and the complexities of trading across a broad and varied portfolio of generating assets, it is not reasonable to expect that bilateral contracting could ever have produced trading mechanisms that could elicit gains from trade as effectively as the ISO auction markets. Externalities in transmission and the management of overall network stability make it so that a fully efficient and reliable electricity market will not arise if bilateral deals are allowed to be made with no

¹² Shanefelter (2006) finds that labor cost savings are particularly pronounced at merchant firms relative to the unregulated affiliates of utilities that purchased many divestitures. It is possible that existing institutional structures may prevent utility affiliates from fully capturing cost savings.

consideration given to their effect on the system. Because of this, in areas where ISOs operate, interaction with the ISO markets is not and should not be voluntary.¹³

Some Limited Cause for Concern and Continuing Oversight: Market Power

Economics text books commonly define market power as pricing above marginal cost. Under this definition, almost every unregulated market is subject to some degree of market power. Therefore, a meaningful analysis of market power in electricity markets should not just ask if it exists (it would be very surprising if it did not), but should ask if market power is impeding the efficient operation of the market and leading to short-term and perhaps more importantly *long-term* (taking into account short-term pricing's effect on entry) consumer harm.

Electricity markets feature highly price-inelastic demand, almost no opportunity to inventory product for peak usage, transmission constraints that at times can limit the set of generators that can physically supply demand in local areas, and plants with capacity constraints and widely-varying operating cost characteristics – all of these characteristics create opportunity for the exercise of market power. The susceptibility of electric markets to the exercise of market power creates a legitimate role for regulators to actively monitor and influence the outcomes of spot markets on an ongoing base.

Every ISO market operates with FERC-approved market power controls, implemented by FERC-mandated independent market monitors, including price caps and auction market offer mitigation. There is no consensus across ISOs as to the exact form of market power mitigation, and revisions to mitigation rules are common. Advocates of limited market mitigation point out that it can be difficult for regulators to correctly identify the costs of electricity generation and that low price caps can prevent the scarcity premiums that could encourage investment or conservation.¹⁴ In most cases, market mitigation is designed to apply only when the market is most susceptible to the exercise of market power, and does not attempt to completely eliminate all pricing above marginal cost. Under the current ISO market designs, market monitors only mitigate offers to an estimate of “true cost” when certain market power screens are triggered, giving generators the flexibility to use

¹³ As is appropriate, bilateral deals are commonly transacted outside of the ISO framework so that the bulk of financial settlement is directly between buyers and sellers. However, to the extent that such deals create congestion on the system, the ISO's nodal pricing system is applicable and the parties to the deals are charged the congestion cost reflected by the difference between the price at the sink and the price at the source.

¹⁴ See The Brattle Group (2007)

their assets in the most profitable (often coinciding with most efficient) manner at times when market power is not a significant concern. The exact parameters specifying when and how generators will have their offers mitigated remain a topic of consideration.¹⁵

There is now a substantial literature on the degree of market power exercised in electricity markets.¹⁶ It is clear that the exercise of market power was one of several contributing factors behind the substantial price increases in California in 2000-2001. For example, Joskow and Kahn (2002) show that the prices that resulted in California averaged at least 50% higher than the competitive benchmark that they calculate. In recent years, studies have found a less pronounced effect from market power. Joskow (2006) claims that “the wholesale markets in the Northeast appear to be very competitive based on a variety of structural, behavioral and performance indicia.” The annual market evaluations published by ISOs commonly show that some evidence of market power persists, but that market outcomes are consistent with “workable competition” and do not produce cause for significant competitive concerns (2006 State of the Market Report, New York ISO).¹⁷ It is likely that these encouraging results reflect the various market power mitigation measures enforced by ISOs and that market power would be a greater concern absent mitigation.

It should be stressed that the literature, including the comparative pricing analysis previously discussed, clearly shows that many recent large rate increases are not the result of market power or market manipulation – they are primarily caused by increasing fuel costs and the basic interaction of supply and demand. For example, consumer advocates expressed skepticism regarding market power when it was announced that default service rates in Maryland’s BG&E utility territory would increase by 72% in 2006. Given the sudden nature of this increase, consumers naturally believed that something must have gone wrong with deregulation and market power was commonly posited as an explanation. In fact, if anything went wrong with restructuring it was in how rates were set *prior* to the rate increases, not after. As restructuring was implemented in Maryland in 1999, rates were frozen for seven years at a level reflecting a discount of 6.5% off of rates that had been in effect since 1993. The rate freezes provided no mechanism to expose consumers to the increasing wholesale prices of 2000-2005 – price increases that were primarily the result of rising fuel prices,

¹⁵ See FERC Docket Nos. RM07-19-000 and AD07-7-000.

¹⁶ For example, see Joskow and Kahn (2002) and Harvey and Hogan (2002) on California, Mansur (2003) on PJM, and Bushnell and Saravia (2002) on New England.

¹⁷ Also see 2007 State of the Market Report, PJM and 2006 Annual Markets Report, ISO-NE. It should be noted that while market monitors generally find energy markets to be competitive, it is not uncommon for them to have competitive concerns about outcomes in the “capacity” markets described below.

not market power. The prices to be charged in 2006 were determined by a competitive procurement process and reflected prevailing wholesale prices. It is not likely that consumers would have perceived these prices to be highly unusual if it hadn't been for the rate caps that had shielded consumers from the fundamental changes that had been transpiring in the marketplace.¹⁸

Still in Development: Mechanisms for Supporting Transmission Investments

Mechanisms for encouraging efficient transmission investments are still developing and evolving. Almost all transmission investments in the past decade have focused on supporting reliability within networks or the addition of spurs needed to connect new generators to the grid (discussed below). There have been essentially no investments that would improve the efficiency of energy trading through increases in interregional transfer capability. To date, the process for eliciting transmission investment have generally been seen as unsuccessful (See Joskow 2005 and Joskow 2006). It is now clear that transmission investments are too “lumpy” to expect that a purely “merchant model” of transmission investment based on the payment of congestion rents could elicit sufficient investment – if a large transmission project completely eliminates congestion, it also completely eliminates the congestion payments that could have helped finance the project.

There is some reason to hope that there will be improvement on the horizon. ISO systems in New England, the Mid-Atlantic and the Mid-West have introduced and expanded regional planning processes that try to allocate investment costs to the market participants who benefit from the investments. Nonetheless, market participants with conflicting interests continue to have a say in the transmission planning process, and it can be very difficult to create governance and cost-allocation structures that allow conflicting interests to unify into decisions that will be efficient for the whole. Furthermore, the siting of any large transmission projects can be subject to the regulatory authority of numerous states, and local opposition can be fierce. The Energy Policy Act of 2005 contains provisions intended to promote efficient interstate commerce by allowing FERC to directly permit projects in certain cases where state approvals are delayed or withheld. There has been significant resistance to the expanded federal authority, and it is not yet clear that it will be fully effective.¹⁹

¹⁸The rate increase became a major issue in the 2006 gubernatorial election, which saw the incumbent lose. All members of the Maryland Public Service Commission were eventually fired, and the full pass-through of prices resulting from the competitive procurement process was temporarily suspended.

¹⁹See “‘Corridors’ of Power are Finding Resistance,” Judy Pasternak, Los Angeles Times, March 24, 2008.

In judging the success of industry restructuring, it must be remembered that the mechanisms for eliciting inter-regional transmission investments were not very effective pre-restructuring. The partitioning of the industry into local utilities and the lack of coordination by state-level regulators left the U.S. with significantly less investment in transmission capacity over the past 30 years than in nations with state-owned vertically integrated utilities (Wolak, 2006). So if the evaluation of the success of restructuring is relative to the previous regulated baseline, it is hard to say that the current market structures are less effective at promoting transmission investment. However, the need for inter-regional transmission capacity is greater now that we have the market structures in place to effectively utilize the transmission system. The lack of transmission investment might be characterized as a missed opportunity, rather than a failure of restructuring.

No clear answers: Who Determines the When, What, Where and How Much of Generation Investments

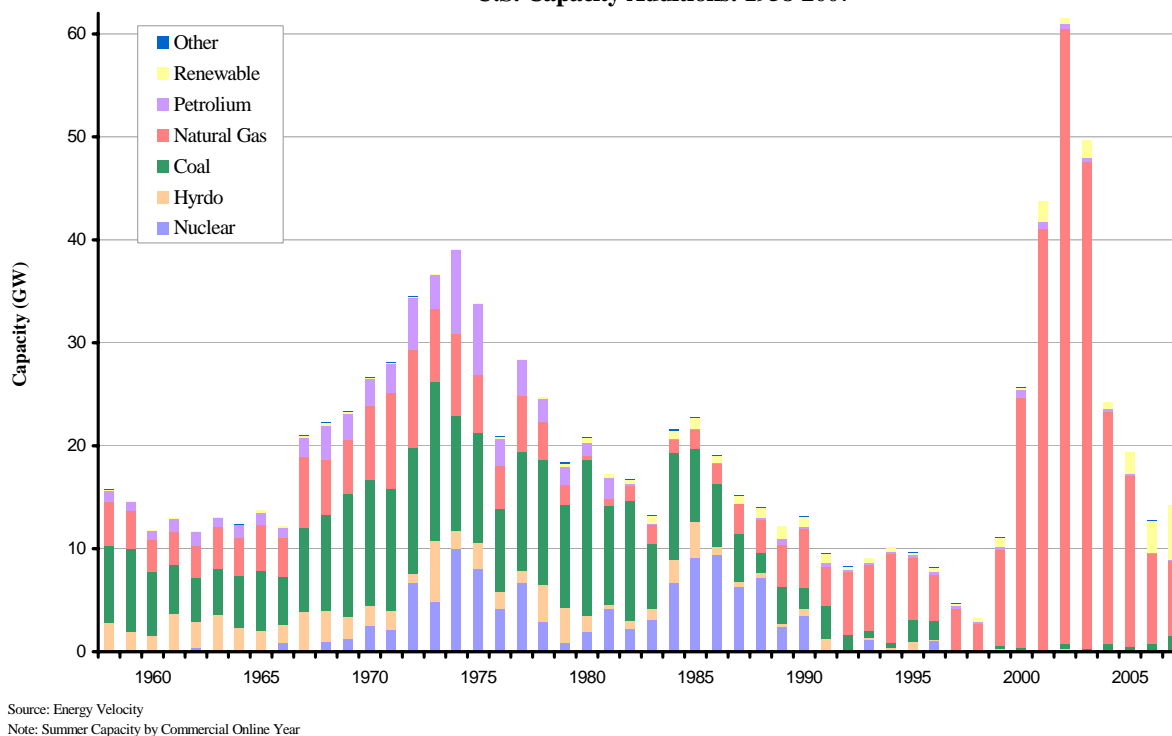
Low natural gas prices and high electricity prices in 1999-2001 led to a boom in the construction of natural gas-fired generation in the following years as depicted in Figure 3. The period from 2000 to 2004 saw more investment in generating capacity than any other 5-year period in history, and almost as much investment as the previous 20 years combined.²⁰ In hindsight it appears that at least some of the investments were made pursuant to overly optimistic forecasts. In recent years, margins in the restructured areas that saw the most entry have fallen to levels that generally do not support further investments, and that in some cases have driven generators into bankruptcy.²¹

²⁰ FERC 2004 State of the Markets Report

²¹ Most of the capacity additions in 2006 and 2007 were pursuant to regulatory incentives/obligations to invest in renewable resources, and/or were made in states that did not restructure and that did not experience the full extent of the earlier investment boom.

Generation investments are less “lumpy” than transmission investments, and tend to be more amenable to unilateral decision-making driven by simple profit motives. However, some level of

Figure 3
U.S. Capacity Additions: 1958-2007



regulation and coordination remains. Regulators have great concern about the consequences of the “bust” portion of the investment cycle as insufficient installed capacity can lead to costly outages on days of peak demand and can potentially undermine the reliability of the system. Furthermore, the presence of offer and price capping creates concern in the industry that the true value of supply in times of scarcity will not be signaled to the market and that therefore there will be insufficient incentive to invest in capacity. Concerns are particularly pronounced regarding the incentives to invest in the high operating cost/low capital cost “peaking” capacity that may only run a few hours a year.

In response to these concerns, ISOs have established obligations on wholesale buyers to ensure that there is enough capacity to meet their share of the peak requirements of the system. In many instances, these obligations apply year-round, including times when there is no possibility of

peak demand. Commonly, the “capacity” product used to meet the obligation gives the buyer no right or option to actually call on the associated power plant to deliver energy.²²

There are important tradeoffs associated with the development of capacity products. Many proponents of market restructuring predicted that market forces would promote more efficient and economically justified investment decisions than did the previous regulatory system. It is possible that the reliance on capacity markets to direct investment decisions could deny at least some of the potential benefits of purely market-dictated investments. Some capacity markets have been found to be susceptible to the exercise of market power. With the possibility for the exercise of market power in energy markets, it is possible that capacity markets could elicit investments in excess of the economically efficient amount and create unnecessary rent transfers to owners of capacity.²³ There currently is not a consensus on the appropriate balance of these tradeoffs, as evidenced by the variation in capacity market mechanisms across regions.

Limited customer choice, but is it necessary?: Retail Pricing

In electricity markets, customer choice programs have been slow to develop, particularly at the residential level. When markets were restructured, it was widely recognized that not all customers would want to shop for a competitive electricity supplier, particularly at the residential level where the transactions costs associated with comparing multiple complicated pricing offers might be significant compared to potential cost savings. In all areas where customer choice was made available, some form of default service by a “provider of last resort” was made available for those who chose not to shop. The pricing mechanism of the provider of last resort has varied considerably. In some areas the distribution utility was designated the provider of last resort, responsible for buying power on behalf of all of its customers, and a rate cap was instituted for many years.²⁴ In other areas, like New Jersey, the provider of last resort designations and rates are determined by the results of a transparent competitive procurement auction run by a state regulator for three year blocks of service. In a few instances, (e.g. San Diego in 2001) wholesale auction prices have been directly passed through to default service customers by their distribution utility.

²² A promising new market design in the PJM region provides performance incentives for generators. PJM’s capacity products are now applicable three years in the future, and current capacity prices now reflect competition from potential resource investment and demand response program development.

²³ By providing a revenue stream for old, inefficient and unreliable plants, capacity markets might also tend to delay retirements beyond the retirement dates that would be economically justified.

²⁴ These caps generally allowed for pre-specified price increases each year and a degree of price variation by season and customer class, but did not link the caps to the auction market prices or other wholesale prices.

In most states, the vast majority of residential customers rely on the default service and there is little switching to alternative retailers.²⁵

A lack of residential customer switching and reliance on a provider of last resort does not necessarily represent a failure or inadequacy of market restructuring. On net, consumers will benefit from efficiencies in plant operations and wholesale trading to the extent that there is *some* mechanism to pass lowered wholesale prices on to retail. In most deregulated industries the mechanism for price pass through is clear – retail competition with customer choice. But retail customer choice is not the only way to expose customers to wholesale prices, and is not clearly necessary. The transparency of wholesale market pricing and the presence of regulated distribution utilities with a billing relationship with customers provides an unusual opportunity in electricity markets. As in New Jersey, public procurement processes can ensure that the rates set for consumers are subject to legitimate and non-discriminatory wholesale market forces, even without direct marketing to residential consumers. The lack of a direct negotiated transaction between each buyer and a single seller does not imply that there is not competition between the sellers. Competition can take place in the submission of procurement auction bids, rather than in the direct solicitation of individual residential users. When wholesale prices are passed through, even if by a default provider, buyers can base their consumption decisions on appropriate market-based pricing signals, and therefore join sellers as participants in a common pooled market.

The possibility of default provider wholesale price pass through does not imply that there is no potential value to retail competition. For example, competitive retailers could add significant efficiency to the market if they are able to increase the exposure of end users to spot market prices.²⁶ On a hot summer day, a customer paying 30 cents per kWh to a retailer that implements a spot-market-based pricing plan is going to be more likely to turn up his thermostat than a customer paying averaged rates of 8 cents per kWh to a default provider. Because they would consume less in high-priced periods, the average cost of supplying a price-responsive customer will be lessened, creating an opportunity for the development of pricing plans that can be beneficial for both the

²⁵The lack of switching is often explained by pricing restrictions placed on default providers during the initial years of retail competition, continuing to date in some cases. In some states (like Maryland prior to 2006) the price caps for default service from the distribution utility were so low that it was infeasible for potential competitive suppliers to compete against the distribution utility. In these areas, end user prices were still dictated essentially by a form of rate regulation. See The Electric Energy Market Competition Task Force Report (2007).

²⁶In most residential cases, current metering technology does not allow for the pass through of real time spot prices or other forms of time of day pricing. Wolak (2007) and others argue that the benefits of installing more sophisticated metering technology far outweigh the costs.

customer and the retailer. Substantial overall cost savings would accrue from conservation when market prices and the marginal cost of supply are high, and total installed capacity needs would be lessened. Furthermore, consumers can be given the incentive to respond to spot prices without exposing them to the volatility of spot prices for the full range of their output. For example, a residential user could be given a choice of rate schedules, each with a different output level available at a fixed rate. Any deviation from the pre-selected output level would be priced at spot market prices.

The success of customer choice programs should be judged relative to the next best alternatives, i.e. by the innovative pricing structures and value added services that competitive retailers bring to the market, not by the number of customers who switch to competitive suppliers from default services.²⁷ To date, alternative retailers have not been successful at getting residential customers to switch to innovative pricing plans – an indication of limited success from customer choice programs, but not an indication of failure of the overall restructuring program. A more serious threat to the success of restructuring exists in areas where consumers have not been exposed to wholesale prices at all, for example in areas where long-term price caps are effective. To achieve the full benefit of restructuring, policymakers must have the will to allow markets to work, and to allow market prices (even if conveyed by a default provider) to encourage conservation when and where conservation is called for.

A Temptation to be Resisted: Rent Capture

Critics of restructured markets often point out that ISO auction markets allow prices to go up to the offer of the most expensive generating unit, allowing all other units to earn more revenue than they need to cover their costs. For example, in an hour of peak demand, an oil-burning peaking plant might set the clearing price at \$200/MWh – a price that is paid not just to the peaking plant, but to nuclear plants with very little marginal cost. Upon seeing the large margins that nuclear plants seem to make in peak hours, a suggestion might come to mind – “Why don’t we design the auction markets to compensate units based on plant-specific marginal cost rather than market-wide marginal cost?” For many reasons this suggestion is ill-conceived:

- If plants were paid only based on their marginal costs, they would not be able to cover their capital costs. It is common that the generators with the lowest operating costs (as in nuclear plants) have the highest construction costs (as in nuclear plants). If entry decisions are

²⁷ See "Why Do We Need Electricity Retailers? Or Can You Get It Cheaper Wholesale?" (<http://econ-www.mit.edu/files/1127>), by Paul Joskow

dictated by profit incentives, a uniform price auction mechanism will ensure that there is sufficient margin above marginal cost available to provide incentive for the development of a mix of different types of generating resources.²⁸

- Even “inframarginal” generation (i.e. generation with operating cost below the market clearing price) can respond to uniform price market signals. For example, nuclear plant operators have incentive to expend whatever resources it takes to ensure that their plants are fully available at times of peak demand.
- Just because *spot* prices clear at the volatile industry marginal cost, does not mean that all output has to or does trade at those prices. The RTO-run auction markets exist for the exchange of energy at the margin. In practice, most generators and Load Serving Entities contract forward to protect themselves from this volatility, often with contracts of year or more lead time.²⁹ In practice, the long-term pricing received by nuclear plants reflects average expected prices and is immune from much of the volatility, risk and potentially large windfalls that would exist if all compensation was based on spot market prices.
- If auction markets are designed as “pay-as-bid” auctions, firms do not have incentive to bid their true costs even absent any market power. In a pay-as-bid auction, a generator that wants to have its offer accepted will try to guess what the clearing price will be and will submit its offer at or just below that price to ensure acceptance. Given imperfect and asymmetric information, there is a risk that a low-cost generator will guess wrong about market prices and submit an offer that is too high and that is therefore not accepted – an inefficient result. Because of the bid inflation and potential for inefficient dispatch, the payments actually made in pay-as-bid auctions are not necessarily less than those made in the uniform price

²⁸ There is nothing unusual about a market that clears at industry marginal cost – it’s the result of the basic textbook model of supply and demand. It is not expected that if commodity producer A has a marginal cost advantage relative to producer B of the exact same commodity, that producer A should be forced to receive less for its output.

²⁹ Note that the existence of forward contracting does not negate the benefits of marginal cost pricing described above. A 500 MW generator with marginal cost of \$50 that has sold 500 MW in a forward market can still actively and efficiently respond to spot price signals. If the spot price materializes at \$45, such a generator can choose to keep its plant off and to purchase in the spot market to fulfill its contractual obligations – a more efficient and profitable outcome than if the generator was obligated to physically produce the energy.

auction designs used by the ISOs.³⁰ The consensus among economists is that in the context of electricity markets, the pay-as-bid auction design is inferior to the uniform price design.³¹

So a simple movement to a pay-as-bid auction design is not the answer, but is there a problem? Could there ever be a reason to worry about excessive compensation of inframarginal capacity and to design mechanisms to prevent it? Critics of restructuring are right to observe that in *some* circumstances it is possible that a fully regulated industry could produce lower average prices paid by consumers than a restructured market based on uniform price market design. In restructured markets, the costs of marginal units tend to influence the compensation of all generating units. If the costs of the units that tend to be on the margin go up, the compensation of all units will also tend to go up, even if the costs of the inframarginal units are unchanged.³² In general, this was not the case under cost of service regulation – rates for the portion of output generated by nuclear plants were typically not increased when the price of natural gas went up. As all earnings of generators are eventually paid by consumers, the average prices paid by consumers will tend to rise more in the short run in a restructured market than in a cost of service environment as fuel prices for price-setting units rise (the opposite being true when fuel prices for price-setting units fall).

But in general, the possibility that inframarginal capacity could earn a profit is not a good reason to impose cost of service regulation and forego the benefits of market restructuring. Regulation should be reserved for cases of natural monopoly, substantial externalities and other market failures – the temptation to use regulation to expropriate rents earned by existing capital stock should generally be resisted. This is good public policy for a nation that wants to encourage efficient investment. If regulation is used to extract profit when the market is up, but not used to enhance profit when the market is down, then would-be investors are put in a no-win situation. The mechanisms of market design should be put in place to address potential market failures where they are foreseeable. As in all industries, some amount of profit in excess of capital cost is not considered a market failure, and should not be expropriated if efficient investments are to be encouraged. Sound

³⁰ An attempt to force generators to submit their true costs in a pay-as-bid auction would require a regulator to determine the allowable levels of true cost. As previously discussed, this can be a very difficult task. Under the current ISO market designs, market monitors only need to mitigate offers to an estimate of “true cost” when certain market power screens are triggered – under a pay-as-bid auction design there would be a need for essentially continuous offer mitigation.

³¹ See Kahn, Cramton, Porter and Tabors (2001).

³² This is generally true even if inframarginal units are selling their output in forward markets as forward prices reflect spot prices.

market design and the opportunity and incentive for market participants to make efficient investments will ensure competitive prices in the long run.

4. Conclusion

In many areas of the country, restructured electricity markets are now producing tangible benefits. There have been very significant improvements in plant operations and in the efficiency of wholesale trading. As market institutions develop there is reason to believe that investment decisions will be made efficiently and that consumers will benefit in the form of lower prices in the long run.

Restructuring of electricity markets faces many challenges, but no challenges that cannot be addressed through effective public policy. Increased exposure of consumers to wholesale spot prices, more effective coordination of transmission investment, and the improvement of market designs that discourage market power while maintaining incentives to invest in generation are important for the long-term development of efficient markets. As regulators consider market reforms, they should look towards the development of these aspects of the competitive marketplace, not towards a return to cost of service regulation.

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