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MARKETS FOR POWER IN THE UNITED STATES: AN INTERIM ASSESSMENT

by

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The transition to competitive wholesale and retail markets for electricity in the U.S. has been a difficult and contentious process. This paper examines the progress that has been made in the evolution of wholesale and retail electricity market institutions. Various indicia of the performance of these market institutions are presented and discussed. Significant progress has been made on the wholesale competition front but major challenges must still be confronted. The framework for supporting retail competition has been less successful, especially for small customers. Empirical evidence suggests that well-designed competitive market reforms have led to performance improvements in a number of dimensions and have benefited customers through lower retail prices.

1. INTRODUCTION

Despite longstanding academic interest (Joskow and Schmalensee (1983)) and some previous experience in other countries, comprehensive electricity sector restructuring and competition initiatives only began to be taken seriously by U.S. policymakers in the mid-1990s.[2] The first U.S. retail competition and restructuring

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[2] Of course, wholesale power markets in which proximate vertically integrated utilities traded power on a daily and hourly basis subject to very limited regulation, have existed in the U.S. for many years. In addition, during the 1980s the Public Utility Regulatory Policy Act (PURPA) of 1978 stimulated the development of a non-utility power sector selling electricity produced primarily from cogeneration facilities and renewable energy facilities to local utilities under long-term contracts (Joskow, 1989). The Energy Policy Act of 1992 also removed important barriers to the broader development of unregulated non-utility generating facilities and expanded the Federal Energy Regulatory Commission's (FERC) authority to order utilities to provide transmission service to support wholesale power transactions. However, these

programs began in Massachusetts, Rhode Island and California in early 1998 and spread to about a dozen additional states by the end of 2000. By that time several additional states had announced plans to introduce similar programs in the near future and a competitive market model for the electricity industry seemed to be sweeping the United States. The primary political selling point for competition in those states that were early adopters was that it would benefit consumers by leading to lower costs and lower prices in both the short run and the long run. The ideological commitment to competition as an alternative to regulated monopoly that characterized the Thatcher government's electricity sector privatization, restructuring and competition program in the United Kingdom (UK) was not a powerful force driving these reforms in the U.S. Indeed, the vast majority of the states that have implemented comprehensive wholesale and retail electricity competition initiatives cast their electoral votes for Al Gore in 2000 and John Kerry in 2004 and neither President Bush nor many of the states that gave him his greatest support have been strong supporters of comprehensive electricity sector restructuring and competitive market initiatives.[3]

The Federal Energy Regulatory Commission (FERC) supported the development of competitive wholesale markets during both the Clinton and Bush administrations. In 1996 FERC adopted rules specifying new requirements for transmission-owning utilities to make available open access transmission service tariffs (Order 888) and provide information about the availability and price of transmission service on their networks (Order 889). In late 1999 FERC embraced a more aggressive restructuring and wholesale

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developments largely reflected modest expansions of competition at the wholesale level built upon a basic model of regulated vertically integrated franchised monopolies.

[3] When President Bush was governor Bush he did support a comprehensive restructuring and competition program in Texas.

market institutional change agenda in its Regional Transmission Organization (RTO) rule (Order 2000). It used various carrots and sticks to induce utilities and state regulators to adopt an aggressive restructuring and competition agenda.

However, the California electricity crisis of 2000-2001 (Joskow (2001)), concerns about market power problems there and elsewhere, phantom trading and fraudulent price reporting and accounting revelations, Enron's bankruptcy, and the financial collapse of many merchant generating and trading companies subsequently took the glow off of "deregulation." Rising wholesale market prices, resulting from rising natural gas and coal prices, closed or reversed the gap between the generation cost component of bundled regulated retail prices and the prices for equivalent generation services purchased in competitive wholesale power markets. This further reduced the interest of consumers and politicians in market-based prices, especially in those states with relatively low regulated prices. The slow pace at which retail customers switched to competitive suppliers in those states that adopted retail competition programs was disappointing and in turn led to a declining number of competitive retail supply options for residential and small commercial customers in many of those states.

Since the year 2000 no additional states have announced plans to introduce competitive reforms and several states that had planned to implement reforms have delayed, cancelled or significantly scaled back their electricity competition programs. Moreover, FERC's efforts to promote a competitive wholesale restructuring and competition model with a small number of RTOs covering large regions of the country and meeting stringent criteria for market design, geographic scope and independence confronted increasing political opposition after 2000. FERC found itself at war with many states in the Southeast and the West as they resisted its efforts to expand wholesale market and transmission institutions that it had identified as being necessary to support efficient competitive wholesale markets in all regions of the country. FERC's proposed Standard Market Design (SMD) rule issued in 2002 created enormous controversy and was withdrawn entirely in July 2005. The pressure from FERC to implement fully and effectively the creation of RTOs pursuant to Order 2000 appears to have receded as well. Re-integration of generation with transmission and distribution has begun to occur in a few states. Even the Cato Institute has lost patience with competitive reforms in electricity and appears to see merit in returning to the good old days of regulated vertically integrated utilities (Van Doren and Taylor (2004)). At the same time, most of the states in the Northeast, a few in the Midwest, and Texas, appear to be committed to moving forward with the development of competitive wholesale and retail markets and to making them work well, though the strength of the policy commitment to competitive electricity markets may have declined in these venues as well.

After nearly 25 years of federal and state restructuring, regulatory reform and deregulation initiatives affecting almost every U.S. industry that had been subject to price and entry regulation prior to 1980, the deregulation policy ship appears to have run aground as it tries to lead the U.S. electric power industry along a path to competition. What is the problem? Are things as bad as opponents of competition suggest? Or does it depend on whether one looks at the glass being half empty or half full? What needs to be done to fix the problems that are really there to make a competitive model more attractive?

One of the challenges associated with providing objective answers to these questions for the U.S. is the lack of any comprehensive assessments of the effects of these reforms on costs, prices, innovation, and consumer welfare of the type that has been done, for example, for the UK (e.g. Newbery and Pollitt (1997), Domah and Pollitt (2001)). This kind of counterfactual analysis is difficult to do well under any circumstances. It is especially challenging when the data available to compare performance under regulated and competitive regimes is extremely limited, as is the case in the U.S. In this paper, I offer an array of "fragments of evidence" to illuminate what we know and what we don't know about the effects of competitive reforms on various performance indicia for the electricity industry in the United States to date. I examine the evolution and effects of both wholesale and retail competition reforms. I view this as an interim assessment because the restructuring and competition program for the electricity sector in the U.S. is clearly incomplete and a work in progress.

2. EVOLUTION OF NEW WHOLESALE MARKET INSTITUTIONS

The foundation of any well-functioning competitive electricity market system (with or without retail competition for all end-use customers) is a well-functioning wholesale market and supporting transmission network operating and investment institutions. Wholesale electricity markets do not design themselves but must be designed as a central component of any successful electricity restructuring and competition program. The U.S. electricity sector's legacy industry structure built upon a large number of regulated vertically integrated monopolies and nearly 150 network control areas was not conducive to creating well functioning competitive wholesale and retail electricity markets (Joskow and Schmalensee (1983), Joskow (2000, 2005a)). However, unlike England and Wales, Norway, Sweden, Spain, Australia, New Zealand, Argentina and other countries, the U.S. did not proceed with its wholesale and retail competition initiatives with a clear coherent blueprint for vertical and horizontal restructuring, wholesale market design, transmission institutions, or retail competition. There has been no federal legislation endorsing a comprehensive national electricity restructuring and competition policy. Horizontal and vertical restructuring has been much more limited than would have been ideal to support a smooth transition to competitive wholesale and retail markets. Rather than relying on a clear and coherent national reform policy with supporting federal legislation, as was the case for the earlier reforms of the airlines, trucking, railroads, and telecommunications, electricity sector reforms have depended on regulatory initiatives taken by FERC under statutes that are 60 years old and by diverse and often inconsistent policies adopted by individual states.

2.1 FERC Takes the Lead

FERC has undertaken a number of initiatives to support the creation of competitive wholesale markets that are consistent with the diverse restructuring and competition policies that have been adopted by different states and associated political constraints on FERC's authority. Orders 888 and 889 issued in 1996 (and subsequently amended a number of times) required transmission owners to provide access to their networks at cost-based prices, to end discriminatory practices against unaffiliated generators and marketers, to expand their transmission networks if they did not have the capacity to accommodate requests for transmission service, and to provide nondiscriminatory access to information required by third parties to make effective use of their networks.

FERC Order 2000 issued in December 1999 contained a new set of regulations designed to facilitate the "voluntary" creation of large Regional Transmission Organizations (RTO) to resolve what FERC perceived as problems created by the balkanized control of U.S. transmission networks and alleged discriminatory practices affecting independent generators and energy traders seeking to use the transmission networks of vertically integrated firms under Order 888 rules.[4] Order 2000 also articulates several important goals for wholesale market institutions and represents a very significant step forward in the framework supporting the development of competitive wholesale electricity markets. These include (a) the creation of independent transmission system operators who will operate the transmission network reliably and economically without being influenced by the financial interests of generators, wholesale and retail markets of power; (b) the creation of large regional transmission networks with common transmission access and pricing rules and common wholesale market institutions to mitigate inefficiencies associated with the balkanized ownership and operation of transmission networks in the U.S.; (c) the creation of a set basic wholesale market institutions to support buying and selling power economically and for allocating scarce transmission capacity efficiently.

In mid-2002 FERC commenced a new rulemaking proceeding to consider a proposal for a "Standard Market Design" or "SMD" that would apply to all transmission-

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[4] *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999). Order 2000 technically makes participation in an RTO voluntary, but there are carrots and sticks available to FERC that will create significant pressure for utilities to join RTOs. Order 2000 does not mandate a particular organizational form for an RTO, however.

owning utilities over which FERC had jurisdiction. The proposed SMD rule enumerated a much more detailed set of wholesale market design requirements : (a) an Independent Transmission Provided (ITP) would be required to assume operating responsibility of all transmission systems, no matter how small; (b) a locational marginal pricing (LMP) based organized day-ahead and real time wholesale market design and congestion management system similar to those that were already in place in PJM and New York; (c) resource adequacy requirements that would obligate all load serving entities (LSEs) to make forward commitments for generating capacity and/or demand response to meet their forecast peak demand plus a reserve margin to be determined through a regional stakeholder process; (d) a regional transmission planning and expansion process would be implemented to identify transmission investment needs for interconnection, to meet reliability requirements, and that are economically justified but which are not being provided by the market; and (e) strong market monitoring and market power mitigation mechanisms would be required, including a $1000/Mwh bid cap for energy and ancillary services in the day-ahead and real time markets was proposed, as well as bidding restrictions to deal with local market power problems.

2.2 Progress in the Development of Wholesale Market Institutions

Despite all of the political controversy surrounding these wholesale market reform initiatives, delays in implementing Order 2000 and the withdrawal of the proposed SMD rule in July 2005, a lot of progress has been made since 1996. As a direct result of FERC's "open access" Orders 888 and 889, all transmission-owning utilities in the U.S. (either directly or through an independent system operator or ISO) now have made available reasonably standardized cost-based transmission service tariffs to support the provision of transmission service on their networks to third parties; provide easily available real time information to third parties about the availability and prices of transmission service on their networks; are required to interconnect independent power producers to their networks, must make their best efforts to expand their transmission networks to meet transmission service requests when adequate capacity is not available to accommodate these requests, must provide certain network support services, including balancing services, to third parties using their networks; and are required to adhere to functional separation rules between the operators of their transmission networks and those who generate and market electricity using that network to mitigate abusive self-dealing behavior. These developments were essential to support entry of independent generators, expansions in wholesale trade, and retail competition as discussed further below.

FERC's RTO rule has also led to important changes in the industry. Table 1 and Figure 1 indicate that as of mid-2005, over 50% of the generating capacity in the U.S. is now operating within an ISO/RTO context (including Texas which is not subject to FERC jurisdiction) and other areas of the country are moving forward slowly with some type of ISO/RTO model. Moreover, most of these ISO/RTOs either have adopted the basic wholesale market principles reflected in the FERC SMD or (in the case of California) are in the process of adopting these institutions or (in the case of Texas) giving them serious consideration (FERC (2005), p.52). I will discuss the attributes of the existing SMD markets in the Northeast presently.

While FERC could not and did not order vertically integrated utilities to divest either their generating facilities or their transmission facilities to separate regulated from competitive lines of business, the combination of state initiatives and market opportunities has led to a considerable amount of restructuring of the ownership of existing generating plants. In 1996 there was about 750,000 Mw of utility-owned electric generating capacity in the U.S. of which investor-owned utilities (IOUs) accounted for about 580,000 Mw. After 1996, about 100,000 Mw of generating capacity was divested by IOUs and another 100,000 Mw transferred to unregulated utility affiliates to compete in the wholesale market. Moreover, between 1999 and 2004 about 200,000 Mw of new generating capacity was completed, about 80% of which was accounted for by unregulated generating companies (independent power companies and unregulated affiliates of utilities). See Table 2. More new generating capacity entered the market between 2001 and 2003 than in any three year period in U.S. history (FERC (2005), p. 59). Indeed, there was so much entry (and so little exit) that by 2003 there was excess generating capacity in most regions of the country. By 2004 over 40% of the power produced by investor-owned companies in the U.S. (i.e. excluding federal, state, municipal and cooperative generation) came from unregulated power plants, up from about 15% in 1996. After a decline in market liquidity following Enron's collapse, during 2004, trading in financial electricity products increased by a factor of ten (FERC (2005), p. 63).

The wholesale market design architecture articulated by FERC in its proposed SMD rule is also spreading, despite all of the controversy surrounding it and FERC's withdrawal of its proposed mandatory SMD rule. The primary features of this wholesale market design, built around a bid-based security constrained dispatch framework with locational or "nodal" pricing (LMP), has been or is being adopted in most of the regions that have created ISOs to operate regional transmission networks (SPP and Texas are the notable exceptions, although a nodal pricing system is being considered in Texas; FERC (2005), p. 52; *Megawatt Daily*, August 19, 2005, page 7). The SMD markets effectively integrate day-ahead, hour-ahead and real time energy prices, determined through a uniform price multi-unit auction framework, with the allocation of scarce transmission capacity. This makes the price of congestion quite transparent since it is reflected in the differences in locational spot energy prices in a way that reflects that physical attributes of the transmission network. Administrative rationing of scarce transmission capacity through the use of Transmission Line Relief (TLR) orders is, in principle, unnecessary, since scarce transmission capacity is rationed by prices and willingness to pay rather than through inefficient pro-rata administrative curtailments. Spot prices for energy reflect the marginal cost of congestion at each location on the network, and in New England and New York they reflect the marginal cost losses as well. Locational prices adjust smoothly to changes in supply and demand conditions on the network consistent with changes in the network's physical constraints. The creation and auctioning of Financial Transmission Rights (FTRs) that reflect the feasible set of allocations of generation to meet demand consistent with network transmission and related reliability constraints provides opportunities for market participants to hedge variations in congestion costs (Hogan (1992), Joskow and Tirole (2000)) and provide the equivalent of firm transmission service.

2.3 Attributes of SMD Markets Operating in the Northeast

The operation of the SMD markets can be illustrated with some examples from New England and New York. In New England the flow of power is typically from North to South, with import constraints into Boston and Southeastern Connecticut under certain supply and demand conditions and export constraints from Maine and Rhode Island to the rest of New England. There are typically significant imports from Canada[5] and more limited imports and exports from and to New York. The associated transmission interconnection facilities are often congested as well. The introduction of an LMP-based wholesale market system has made this congestion transparent, yields associated price signals and facilitates the efficient allocation of scarce transmission capacity. In 2004, the average day-ahead LMP at the border between New Brunswick and Maine was about \$53/Mwh and the average LMP in Connecticut was about \$62/Mwh. The price difference reflects network congestion and thermal losses. The 17% difference in prices may not seem like much and perhaps not worth the effort. However, the annual average locational prices hide significant variations over time and across generation nodes as supply and demand conditions change. For example, Table 3 displays the average prices aggregated for each New England load zone for hour 17 on July 19, 2005, a hot day when the peak demand in New England hit a new record. It is evident that the price in Boston (NE Massachusetts) is two and a half times the price in Maine, reflecting import congestion into the Boston area. The zonal prices are much higher in Boston than in Connecticut at this hour even though on average during the year, Connecticut tends to be more congested than Boston. This shows that variations in spot prices for power reflect the fact that congestion patterns can change from one hour to another.

The price differences in New York State between New York City and Upstate New York are much larger than those observed for New England. In 2004 energy prices in New York City average nearly \$90/Mwh while the average energy price in upstate

[5] Imports from outside the U.S. account for a very small fraction of aggregate U.S. electricity supplies.

New York was about $50, reflecting the import constraints into New York City and the high costs of the generating units located in the City (New York ISO (2005), p. 8).

2.4 Market Power and Its Mitigation

The development of competitive wholesale markets in the U.S. has been heavily influenced by concerns about market power. The potential for market power to be a particularly severe potential problem in electricity markets was recognized many years ago (Joskow and Schmalensee (1983), Chapter 12). It arises as a consequence of transmission constraints that limit the geographic expanse of competition, generation ownership concentration within constrained import areas, the non-storability of electricity, and the very low elasticity of demand for electricity (Joskow (1997), Borenstein (2002)). Generator market power was a serious problem for several years following the launch of the privatization, restructuring and competition program in the UK (Wolfram (1999)). Concerns about market power in the U.S. were reinforced by the events in California in 2000-2001 (Borenstein, Bushnell and Wolak (2002), Joskow and Kahn (2002)) where market power and the exploitation of market design imperfections contributed to the explosion in wholesale prices beginning in June 2000.

Market power monitoring and mitigation has been a central focus of FERC's wholesale market policies. However, despite all of the concerns about market power, the wholesale markets in the Northeast appear to be very competitive based on a variety of structural, behavioral and performance indicia (New York ISO (2005), pp. iii, vii; ISO New England (2005), pp. 98-106; PJM (2005), pp. 48-67). The primary exceptions emerge when supply and demand conditions lead to transmission constraints that create small "load pockets" within which the supply of generation is highly concentrated.

However, market monitoring and mitigation protocols appear to have been reasonably successful in mitigating the ability of suppliers to exercise significant market power in these situations as well. Indeed, these measures may have been too successful, constraining prices from rising to competitive levels when demand is high, capacity is fully utilized, and competitive market prices should reflect scarcity values that exceed the price caps in place in the SMS markets (Joskow and Tirole (2005a)), a subject to which I shall return presently.

2.5 Intertemporal and Locational Price Convergence

Electricity is non-storable and supply and demand must be balanced with the ultimate in just in time production. This leads to significant volatility in spot market prices. However, the ability of suppliers and consumers to respond to large changes in real time prices is limited. This is especially true for suppliers or consumers in neighboring control/market areas. Many economic decisions in electricity markets are based on forward price signals in the hour-ahead, day-ahead, and longer forward markets. Market power is also more difficult to exercise in forward markets, making it attractive to move more price commitments into forward markets. Price convergence (intertemporal trading profits are arbitraged away) between the day-ahead, hour-ahead and real time markets is an important indicator of market performance. Price convergence in the SMD markets is reasonably good and has improved over time as these markets have been refined. Well designed virtual bidding opportunities can and have helped to improve price convergence and improve market efficiency (New York ISO (2005), pp. 10-16; ISO-New England (2005), p. 49)

Because the ISOs in the Northeast have adopted similar market designs, the integration of these markets has been facilitated and barriers to trade between these markets continue to decline, though "seams" issues continue to be an area where more work is needed (New York ISO (2005), pp. 66-73). The data in Figure 2 have been assembled to provide a simple picture of the interaction between these regional market areas as supply and demand conditions change. Figure 2 displays the day-ahead peak period (16 day-time hours on weekdays) prices for power at the Massachusetts hub, New York City (NY-J), the New York Hudson Valley (NY-G), the PJM West hub, and the Cinergy hub in the Midwest, for several days during the first six months of 2004. These hubs are all interconnected and power can be traded between them. If there were no congestion, no losses, efficient transmission pricing, and no institutional barriers to trade across these areas the prices would be equal to one another. In other words the Law of One Price would prevail. The general patterns of power flows in the Northeast are from the Midwest toward the East and from the North (Quebec, New Brunswick and Maine) to the South. New York City and Long Island are more frequently import constrained by transmission and related reliability constraints than other areas in the Northeast. It should be clear from Figure 2 that the Law of One Price does not prevail in Eastern electricity markets.

The data in Figure 2 should be read starting at the far left with the locational day-ahead prices for mid-January 2004. It was extremely cold in the Northeast at this time, with temperatures falling to their lowest levels in over 50 years. As a result, demand for both natural gas and electricity were unusually high for this time of year. The electricity market in New England in particular was severely stressed despite the fact that peak demand was significantly lower than the quantity of installed capacity. Many generating plants were out of service due to routine maintenance, weather related problems, and the allocation of gas supplies between electricity generation and other uses (New England ISO (2004), FERC (2005), pp. 13-23). The demand for imported electricity into the Northeast from the Midwest increased and transmission capacity from the Midwest to the East became congested. We can see this in the separation of prices at various locations in mid-January. There was plenty of less costly generation in western Pennsylvania and the Midwest that could have served demand further east, but the transmission capacity to move the power east became constrained. Moving to the right in Figure 2 we see that as the weather returned to more normal levels as the year progressed the differences in locational prices compress significantly. New York City always has the highest prices because imports into New York City are frequently constrained by transmission limitations and some unique reliability considerations. The Mass Hub and Hudson Valley prices are about the same and often close to the PJM West prices. The Cinergy hub prices are always the lowest. Then as we move into June 2004 on the far right of Figure 2 we see the prices separate again as hot weather moves into the Northeast and demand for imported electricity rises again.

The markets in the Northeast and Midwest are clearly closely linked together, though spot energy prices exhibit locational differences as a result of congestion, losses, transmission service prices that exceed the marginal cost of providing transmission service (Joskow 2005b), and inefficiencies in the way these organized markets are linked together. Additional investment in transmission capacity, more effective utilization of the transmission capacity in place, more efficient pricing for transmission service, and enhanced integration and harmonization of the markets in New England, New York, PJM and MISO can reduce these price gaps and increase efficiency.

2.5. Wholesale Prices and Other Performance Indicia

It is difficult to measure the effects of the changes in wholesale market structure and institutions on wholesale market prices in the Northeast and Midwest since the mid-1990s when the reforms began. The wholesale markets that existed in 1996 were essentially "excess capacity" markets involving trades of electric energy between vertically integrated utilities who relied on regulated tariffs and captive retail customers to secure the capital costs for these facilities. Moreover, fuel prices, especially natural gas prices, have escalated dramatically since 1996 and hundreds of thousands of megawatts of unregulated generating capacity must cover both their capital and operating costs through the sales of energy, ancillary services and capacity in competitive wholesale markets. Congestion costs are now transparent and revealed by differences in locational prices while they were once hidden in redispatch and unit commitment costs. There are some fragments of evidence about changes in wholesale market prices to consider, however.

A study comparing what prices would have emerged under cost of service regulation with the cost of buying that power in PJM's wholesale markets for three utilities in PJM, taking input cost changes into account, found that the cost of power purchased in PJM's wholesale market was lower than what the cost of that power would have been under continued cost of service regulation (Synapse Energy Economics (2004)). Wholesale market prices in New England, adjusted for changes in fuel prices, fell between 2000 and 2004 (See Table 4). Moreover, despite the fact that nominal wholesale market prices in the Northeast have risen along with fuel prices, the "all in" cost of power in the wholesale market (energy, ancillary services and capacity costs) is lower than the inflation adjusted regulated cost of generation service that was embedded to the regulated retail prices for many of the utilities in the Northeastern states in the late 1990s. For example, in the late 1990s, many northeastern utilities had average regulated costs of generation service in the 6 cent to 8 cent/kWh range (Joskow (2000)) or about 7 to 9.5 cents/kWh at current general price levels (*without* taking account of fuel price increases specifically). For the period 2002-2004, the all-in cost of power in the wholesale market in New York State outside of New York City and Long Island averaged about $50/Mwh. For New England the "all-in" price of wholesale power was about $50/Mwh over the period 2001-2004. In both cases this is significantly lower than the regulated cost of generation service embedded in retail prices prior to these reforms for many utilities in this region.

We should recognize, however, that cost-of-service regulation provided consumers with a hedge against fluctuations in fuel prices. In competitive markets the spot market price of electricity will reflect the marginal cost of the supplier that clears the market or the (much higher) value of unserved energy (or cost of lost load) when the market is cleared on the demand side under "scarcity conditions" when capacity is fully utilized Accordingly, if the marginal generating capacity that clears the market is natural-gas fired, the all-in market price of wholesale electricity will vary with variations in the price of natural gas, other things equal. Under cost-of-service regulation the all-in cost of generation service would be less sensitive to movements in natural gas prices in this case since the regulated costs of hydro, nuclear and coal-fired capacity would not vary directly with natural gas prices. Under cost-of-service regulation, natural gas price increases would have been reflected in retail prices in proportion to the fraction of generation accounted for by gas-fired capacity under cost-of-service regulation. Deregulation removes this hedge, making wholesale prices more sensitive to variations in the prices for fuel used by the marginal generating capacity that clears the market. If natural gas prices stay very high, it may turn out to be the case that in the short run, the costs of purchasing generation supplies out of competitive wholesale market will be higher than the costs consumers would have paid under regulation as the rents associated with unregulated hydro, nuclear and coal capacity will now accrue to the owners of this capacity rather than to consumers as a consequence of the loss of this regulatory hedge. On the other hand, under regulation when there was excess capacity, prices rose to allow recovery of fixed costs while with competition excess capacity should lead to lower prices, other things equal. Consumers also were asked to pay for large generating plant construction cost overruns under regulation, while with competition it's the investors that bear construction cost overrun risks. We have too little experience to know how much these countervailing forces will affect generation service prices in the long run.

One of the benefits expected from the introduction of competitive wholesale markets was that it would provide incentives to improve the performance of the existing fleet of generating plants --- availability, non-fuel operating costs, heat rates (Joskow (1997)). Availability of generating capacity has increased over time in both New England and New York (ISO New England (2005), page 114; New York ISO (2005), p. 18). Equivalent availability factors increased significantly in PJM from 1994 to 1998 and have been roughly constant since then with some year-to-year variability (PJM (2005), p.168). Markiewicz, Rose and Wolfram (2004) find that the operating costs of generating plants fell more in states in the process of restructuring to support competition than in states which were not in the process of adopting restructuring programs. Bushnell and Wolfram (2005) find that divested generating plants and those subject to incentive regulation mechanisms improved their fuel efficiencies compared to their peers without high-powered incentives. Though the evidence is still limited, it tends to support the conclusion that competition has provided incentives to increase generating unit performance.

3. IMPROVING WHOLESALE MARKET PERFORMANCE

While there has certainly been a lot of progress made in creating good competitive wholesale market institutions, and there has been a lot of valuable learning from experience, there is still a lot more work to do. The necessary reforms go well beyond modifications in the details of Orders 888/889 as some have suggested is the appropriate focus of future FERC policy initiatives. Let me identify and discuss very briefly four areas where I think significant performance improvements need to be made.

3.1 Incentives to invest in new generating capacity

Despite the enormous quantity of new generating capacity that entered service between 2000 and 2004, and the existence of excess capacity in most regions of the country, policymakers are now very concerned about future shortages of generating capacity resulting from retirements and inadequate investment. Many of the merchant generating companies that made these investments subsequently experienced serious financial problems and several went bankrupt. The liberal financing arrangements available to support these projects during the financial bubble years are no longer available and project financing for new generating plants is difficult to arrange unless there is a long term sales contract with a creditworthy buyer to support it. Rising natural gas prices have changed the economic attractiveness of the combined-cycle gas turbine technology that has dominated the fleet of new plants. The quantity of new generating capacity coming out of the construction pipeline is falling significantly (see Table 2). Very little investment in new merchant generating capacity is being committed at the present time, aside from wind and other renewables that can obtain favorable tax treatment and other financial and contractual incentives. System operators in the Northeast and California are projecting shortages and increases in power supply emergencies three to five years into the future, recognizing that developing, permitting and completing new generating plants takes several years. Unlike the situation in England and Wales, the U.S. does not have large amounts of mothballed capacity that can come back into service quickly as prices rise.

On the one hand, a market response that leads prices (adjusted for fuel costs) and profits to fall and investment to decline dramatically when there is excess capacity, is just the response that we would be looking for from a competitive market. For 25 years prior to the most recent market reforms the regulated U.S. electric power industry had excess generating capacity which consumers were forced to pay for through regulated prices. The promise of competition was that investors would bear the risk of excess capacity and reap the rewards of tight capacity contingencies, a risk that they could try to reallocate by offering forward contracts to consumers and their intermediaries. At least some of the noise about investment incentives is coming from owners of merchant generating plants who would just like to see higher prices and profits. On the other hand, numerous analyses of the performance of organized energy-only wholesale markets indicate that they do not appear to produce enough net revenues to support investment in new generating capacity in the right places and consistent with the administrative reliability criteria that are still applicable in each region. Moreover, while capacity obligations and associated capacity prices that are components of the market designs in the Northeast produce additional net revenue for generators over and above what they get from selling energy and ancillary services, the existing capacity pricing mechanisms do not appear to yield revenues that fill the "net revenue" gap. That is, wholesale prices have been too low even when supplies are tight.

The experience in PJM is fairly typical. Table 5 displays the net revenue that a hypothetical new combustion turbine would have earned from the energy market plus ancillary services revenues in PJM if it were dispatched optimally to reflect its marginal running costs in each year 1999-2004. In no year would a new peaking turbine have earned enough net revenues from sales of energy and ancillary services to cover the fixed costs of a new generating unit and, on average, the scarcity rents contributed only about 40% of the costs of a new peaking unit. Based on energy market revenues alone, it would not be rational for an investor to investment in new combustion turbine or CCGT capacity in PJM. PJM has always had capacity obligations which it carried over into its competitive market design and in theory capacity prices should adjust to clear the market (Joskow and Tirole (2005b)). However, even adding in capacity revenues, the total net revenues that would have been earned by a new plant over this six year period would have been significantly less than the fixed costs that investors would need to expect to recover to make investment in new generating capacity profitable.

This phenomenon is not unique to PJM. Every organized market in the U.S. exhibits a similar gap between net revenues produced by energy markets and the fixed costs of investing in new capacity measured over several years time (FERC (2005), p. 60; New York ISO (2005), pages 22-25). There is still a significant gap when capacity payments are included. The only exception appears to be New York City where prices for energy and capacity collectively appear to be sufficient to support new investment, though new investment in New York may be much more costly than assumed in these analyses (FERC (2005), page 60). Moreover, a large fraction of the net revenue there comes from capacity payments rather than energy market revenues (New York ISO (2005), p. 23).

I have discussed elsewhere some of the regulatory, system operation and market imperfections that seem systematically to lead organized wholesale energy markets to produce inadequate incentives for new investment in generation consistent with prevailing engineering reliability criteria (Joskow (2005a), Joskow and Tirole (2005b)). The problems include: (a) price caps on energy supplied to the market and related market power mitigation mechanisms that do not allow prices to rise high enough during conditions when generating capacity is fully utilized to provide energy and operating reserves to meet reliability constraints. Under these conditions supply and demand should be balanced by responses on the demand side to high prices that reflect the value of lost load, producing significant competitive scarcity rents for generators; (b) price caps on capacity payments in the market designs that incorporate capacity obligations and capacity prices; (c) actions by system operators that have the effect of keeping prices from rising fast enough and high enough to reflect the value of lost load during operating reserve emergencies when small changes in system operating procedures can lead to very large changes in prices and scarcity rents needed to cover fixed costs; (d) reliability actions taken by system operators that rely on Out of Market (OOM) calls on generators that pay some generators premium prices but depress the market prices paid to other suppliers; (e) the absence of adequate spot market demand response to allow prices to play a larger role in balancing supply and demand under tight supply conditions; (f) payments to keep inefficient generators in service due to transmission and related constraints rather than allowing to be retired or be mothballed, (g) regulated generators operating within a competitive market that have poor incentives to make efficient retirement decisions, depressing market prices for energy and (h) engineering reliability rules that have not been harmonized with market mechanisms and may implicitly impose costs of meeting reliability standards that are significantly greater than consumers would be willing to pay in a well functioning competitive market.

This "resource adequacy" problems arising from imperfections in spot energy markets are now widely recognized by policymakers. FERC's proposed SMD rules contained requirements that system operators implement mechanisms to assure resource adequacy. Efforts are being made to reform capacity obligations and associated market mechanisms to try to deal with them (Cramton and Stoft (2005)). More could be done to reform spot energy markets to allow prices to rise to appropriate competitive levels when generating capacity is fully utilized, to expand demand side participation in the spot market, and to better harmonize reliability rules and reliability actions taken by system operators with market mechanisms.

3.2 Improve the framework for supporting transmission investment and expanding effective transmission capacity

As wholesale markets have developed congestion on the transmission network has increased (Joskow (2005b, 2005c)) significantly. Investment in transmission capacity has not kept pace with the expansion in generating capacity and changes in trading patterns (Hirst 2004). Transmission congestion and related reliability constraints create load pockets, reducing effective competition among generators and leading policymakers to impose imperfect market power mitigation rules that create other distortions.

In addition to the effects of transmission congestion on wholesale power prices and the social costs of congestion, a congested transmission network makes it more challenging to achieve efficient wholesale market performance. Congestion increases market power problems and the use of highly imperfect regulatory mitigation mechanisms to respond to them. Congestion makes it more challenging for system operators to maintain reliability using standard market mechanisms, leading them to pay specific generators significant sums to stay in the market rather than retire and to rely more on OOM calls that depress market prices received by other suppliers (FERC (2005), pp. 6, 23, 61). In New England, the amount of generating capacity operating subject to reliability contracts with the ISO has increased from about 500 Mw in 2002 to over 7,000 Mw projected (including pending contracts) for 2005 (ISO-New England (2005), p.80).[6] These responses to transmission congestion undermine the performance of competitive

[6] FERC has ordered the ISO to replace these agreements with a locational capacity market mechanism built around an administratively determined "demand curve" for generating capacity. However, implementation has now been delayed until at least October 2006.

markets for energy, exacerbate the net revenue problem discussed above, and lead to additional costly administrative actions to respond to market imperfections resulting from transmission congestion.

The existing framework for supporting transmission investment is seriously flawed. Regulatory responsibilities are split between the states and the federal government in sometimes mysterious ways (Joskow (2005b)). FERC initially supported a flawed "merchant investment" model (Joskow and Tirole (2005a)) and confused issues of who pays for transmission upgrades with questions about whether such upgrades are mediated through market mechanisms (e.g. in return for FTRs) or regulatory mechanisms or a combination of both. Transmission investments driven by reliability considerations and transmission investments driven by congestion cost reductions are inherently interdependent but have been treated by FERC and some system operators as if they were completely separable (Joskow (2005c)). The U.S. does not even collect statistics on transmission investment and transmission network performance that are adequate to evaluate the performance of the network (U.S. Energy Information Administration (2004)). Despite promoting performance based regulation for transmission in Order 2000, there has been little progress in developing and applying a coherent incentive regulation framework in practice. Much of the increase in transmission investment that is reported to have occurred is associated with interconnections of new generators and associated network reinforcements to meet reliability criteria. There has been little if any investment in transmission facilities to increase interregional transfer capability.

While the situation is improving with the adoption of more comprehensive transmission planning and investment processes in New England, PJM and the MISO, the transmission investment and regulatory framework has a long way to go before is will stimulate needed investments, to improve network performance and to create a transmission network platform that supports efficient competitive markets for power with less regulation and fewer administratively determined reliability contracts.

3.3 Continue to reduce "seams" problems that create barriers to trade between market areas.

The wholesale markets operating on the three synchronized U.S. transmission networks (Eastern Interconnection, Western Interconnection, and ERCOT (Texas)) are regional markets whose effective geographic expanses have grown over time. However, there remain opportunities to further reduce barriers to trade and to expand their geographic scope. The differences in market prices observed for wholesale between different areas in the Northeast and Midwest (Figure 2) are partially a consequence of transmission network congestion. However, the price differences are also caused by regulated transmission prices that create an inefficient wedge between energy prices in different areas. They also reflect incompatibilities in the wholesale market mechanisms in different ISOs that limit trading in the spot markets operated in each area. Long distance trades in energy can still incur multiple transmission charges that include "pancaked" sunk cost allocations and make efficient trades uneconomical. Differences in the timing of the bidding and market clearing mechanisms and asymmetric treatment of generators in different control areas can further inhibit short-term trading opportunities and lead to inefficient allocation of scarce transmission capacity. The efforts by New England and New York and by PJM and the MISO to reduce these trading barriers are admirable and these efforts should be expanded to other regions.

3.4 Increase demand response

In markets for most goods and services when demand grows and supply capacity constraints are reached prices rise to ration demand to match the capacity available to provide supplies to the market. In electricity markets, however, as generating capacity constraints are reached, relatively little demand can be rationing by short term price movements and, instead, must by rationed with rolling blackouts. The possibility of broader uncontrolled cascading blackouts and regional network collapses further exacerbates this problem, necessarily leads to regulatory requirements specifying operating reserves, operating reserve deficiency criteria and associated administrative actions by system operators to balance the system to meet voltage, stability and frequency requirements in an effort to avoid cascading blackouts (Joskow and Tirole (2005b)). The challenges faced by network operators to maintain system reliability and avoid non-price rationing of demand would be reduced if additional demand-side instruments were at its disposal. These include more customers who can see and respond to rapid changes in market prices and expanded use of price-contingent priority rationing contracts (Chao and Wilson 1987).

Too little demand side response has been developed to date. In New England, with a peak demand of over 26,000 Mw only a few hundred Mw is available to the system operator for use during power supply emergencies (ISO New England (2005), p.91). New York, with a peak demand of over 30,000 Mw has done better with about 1700 Mw of “quick” demand response (New York ISO (2005)). The demand response instruments that are available are poorly integrated with spot markets and are likely to have the effect of depressing prices inefficiently. Moreover, the prices that are paid for demand response or the prices that can be avoided by responding to price signals are too low compared to the cost of carrying generating capacity reserves to meet planning reserve margins. Improving demand response should be given higher priority in wholesale market design.

4. RETAIL COMPETITION

In the policy arena, the primary selling point for competition in electricity in most states has been the prospect for *retail competition* or *retail customer choice* to lead to lower *retail* electricity prices. My assessment of the status of retail competition among the states is displayed in Figure 3. All of the states, except for Texas, that have implemented and sustained comprehensive retail competition programs are in the Northeast and upper Midwest. These states had regulated retail prices that were among the highest in the U.S. in 1996 (Joskow (2000)). California suspended its retail competition program in 2001 as did Arizona (where it never really got started). Three states have programs that are limited to selected industrial customers. All of the other states either withdrew their existing plans to introduce retail competition after the California electricity crisis or never adopted a retail competition plan. There appears to be little interest today in those states without retail competition to introduce it and some pressure in states that have it to repeal it.

With a retail competition program, an electricity customer's bill is "unbundled" into regulated non-bypassable "delivery" component with a price P_R (transmission, distribution, stranded cost recovery, retail service costs to support default services) and a competitive component with a price P_C (generation service, some retail service costs, and perhaps an additional "margin" to induce customers to shop). The customer continues to buy the regulated delivery component from the local distribution company but is free to purchase the competitive component from competing retailers which I will refer to as retail Electricity Service Providers (ESP).

In most jurisdictions that have introduced retail competition programs, the incumbent distribution company is required to continue to provide regulated "default service" of some kind to retail consumers who do not choose an ESP during a transition period of from five to ten years. The terms and conditions of default service vary across the states, but typically default service prices have been calculated in the following way. Regulators start with the incumbent's prevailing regulated cost of generation service. A fraction of this regulated generation cost component may be determined to be "stranded generation costs" that can be recovered from retail consumers over some time period and is included in the regulated price of delivery services P_R. The residual is then used to define the initial "default service" price P_C or the "price to beat" by ESPs seeking to attract customers from the regulated default service tariffs available from the incumbent utility. The value of P_C is then typically fixed for several years (sometimes with adjustments for fuel prices). After the transition period the default price is expected to equal at least the competitive market value of providing competitive retail services to consumers.

In many states the regulated default service price was either set or eventually fell below the comparable cost of power in the wholesale market. In some cases, rising wholesale prices caused by higher gas prices erased or reversed the gap between the default price and the wholesale price. For example, in Pennsylvania PPL has a default price of 5.5 cents/Kwh for residential customers that is based on a formula defined when retail competition was initiated in Pennsylvania in 2000.[7] The forward *wholesale* price for power delivered at PJM West for Calendar year 2006 (16 hours per day for six days per week) was about 8 cents/kWh on August 23, 2005. PPL's default price is not scheduled to rise to market levels until 2010. Obviously, ESPs will find it difficult profitably to buy power at 8 cents and sell it at under 5.5 cents to attract customers away from default service.

4.1 Customer Switching Patterns

Most states that have introduced retail competition have experienced fairly similar and generally disappointing switching patterns. Relatively few residential and small commercial customers switch to ESPs and the migration from the incumbent's default service to competitive service for all but the largest customers is very slow (Joskow 2005a). Larger industrial customers are more likely to switch to ESPs and to do so much more quickly than residential customers.

To provide a typical example, Table 6 displays the retail switching statistics for Massachusetts, one of the first states to introduce retail competition, for February 2004 and May 2005. Retail competition was introduced for all customers in Massachusetts in early 1998, so consumers have had seven years to adapt to it. Only about 7% of the residential customers accounting for 6% of residential consumption have switched. There are few ESPs offering service to residential and small commercial customers active in the market. Over a similar period of time, over 50% of the residential customers switched to competing suppliers in England and Wales and there are several competing retail suppliers offering service to residential (domestic) customers there. Switching in Massachusetts has been greater among small, medium and large commercial customers,

[7] *Megawatt Daily*, August 18, 2005, pages 1 and 10.

with the largest electricity consumers in each category being more likely to switch. After seven years of retail competition, only 8% of the total retail customers accounting for 34% of electricity consumption have switched to competitive suppliers. However, switching among all classes of customers (and the number of ESPs seeking customers) now seems to be increasing since the regulated default service (called standard offer service in Massachusetts) ended in March 2005 and all default service prices began to reflect wholesale market values. This appears to be the reason that we see a big jump in switching activity between February 2004 and May 2005.

Texas has had the most successful U.S. retail competition program as measured by customer switching activity. Retail competition began officially in Texas in January 2002, though there was a pilot program implemented before that and customers who had switched before the official program began could stay with the ESPs they had chosen. Texas adopted a retail competition program similar to that in the UK. Regulated default service was limited to smaller residential and commercial customers, the price for this service was set at (or above) wholesale market levels, the "price to beat" left an additional margin for competitive suppliers, and incumbents were given incentives to shift their retail customers to competitive suppliers. By June 2005 about 15% of the residential customers had switched to ESPs and the fraction continues to grow (Public Utility Commission of Texas (2005)). For commercial customers, 20% of the customers and 46% of the load had switched to ESPs by June 2005, while 38% of the largest customers, accounting for 63% of the load, had switched to an ESP. Virtually all of the largest customers have negotiated competitive contracts either with the retailing affiliate of their incumbent utility or an unaffiliated ESP. Unlike Pennsylvania, where the fraction of customers served by ESPS has declined over time (not the sign of a successful product), retail switching shows a monotonic increasing trend in Texas. Texas is also the state that has the largest number of active ESPs competing to sell service to retail consumers.

The biggest problem facing ESPs is "competition" from regulated default service and the unpriced option to go and return from regulated to competitive retail prices and back again that is often embedded in it. If regulated default service prices are set below the comparable wholesale market price of power, ESPs will not be able to compete for retail customers. Moreover, allowing customers that choose to take service from an ESP to return to a regulated tariff when wholesale prices are high, without being charged an appropriate price for this option, seriously undermines the development of retail competition. This leads to a very unstable customer base for ESPs, and undermines incentives for ESPs to enter into long term forward contracts or acquire generating assets to support their retail supply portfolios. While I remain unconvinced that residential and small commercial consumers are likely to benefit from retail competition, compared to simply relying on the local distribution company to buy power for them in the wholesale market, the worst of all worlds is the adoption of policies that rely on retail competition evolving but make it uneconomical for customers to switch to an ESP. Policymakers need to choose whether or not they really have faith in retail competition and adopt policies that either support its development if they do or rely instead on a wholesale competition model in which distribution companies procure power competitively if they don't.

5. RETAIL PRICE PATTERNS

The promise of lower prices was the political selling point for competition in most states. Policymakers in many states are asking whether or not competition is benefiting consumers through lower prices. We should be able to answer their questions. But lower compared to what? Lower than they were in 1996? Lower than they would have been if the regulated monopoly regime had continued? Lower in real dollars or nominal dollars? Policymakers were not particularly clear about the relevant comparisons as they were selling or opposing pro-competition reforms over the last decade. Given changes in fuel prices, demand, technology and environmental constraints, the only sensible comparison is between what prices are at a point in time under a competitive institutional framework and what they would have been if the prevailing regulated monopoly framework had continued. Unfortunately, this is a difficult counterfactual comparison to make. It is complicated by the large increase in natural gas prices (Figure 4) and the entry of almost 200,000 Mw of new mostly gas fired generation since 1998 (Table 2). Under a competitive model retail prices reflect the aggregation of competitive components (generation and retail supply) and regulated components (transmission and distribution). Moreover, since the industry structure and regulatory frameworks have varied from state to state, the answer to this question could very depend on variations in the nature of regulatory institutions and the performance of regulated firms in different states.

To place the analysis that follows in context, Figure 5 displays a time series of average *real* residential and industrial electricity prices from 1960 through 2004 for the U.S. as a whole. Average real U.S. electricity prices fell virtually continuously from the early 20th century until about 1972. The combination of rising inflation, rising nominal interest rates, the exhaustion of scale economies in generation, and large increases in fuel prices in connection to the oil shocks in 1973 and 1979 reversed this historical trend. As fuel prices, inflation and nominal interest rates began to fall in the early 1980s, real electricity prices began to fall as well (Joskow (1974, 1989)). While some trace the start of policy initiatives to promote competition to the implementation of PURPA in the early 1980s, it is widely believed that PURPA, as it was implemented in the states with the greatest enthusiasm for it, led to higher rather than lower retail prices (Joskow (1989)). Accordingly, it would be incorrect to conclude from Figure 5 that there is a causal relationship between the implementation of PURPA and the renewed trend of lower real electricity prices. The major contemporary competitive initiatives began to be realized after 1996 with Orders 888 and 889, the retail and wholesale restructuring initiatives in California and several Northeastern states in 1998, the associated divestiture of regulated generating plants that became unregulated Exempt Wholesale Generators (EWG) as permitted by reforms contained in the Energy Policy Act of 1992, the entry of a large amount of new EWG capacity in many areas of the country following the state and federal reforms after 1996, and the subsequent FERC and state reforms that I have already discussed. There is certainly no noticeable dramatic change in the trend of average real U.S. electricity prices displayed in Figure 5 that can be readily associated with these post-1996 reforms. If anything, the rate at which real electricity prices fell seems to have declined as these reforms were implemented. Accordingly, the aggregate time series data alone tell us little about the effects of competition and regulatory reforms on the prices paid by consumers.

We can slice the data another way and compare the trends in retail prices in states that adopted retail competition reforms, often along with other restructuring reforms that supported the development of competitive wholesale markets, with the price trends in states that did not adopt such reforms. Figure 6 compares the changes in real residential electricity prices for states that introduced retail competition and those that did not between 1996 and 2004.[8] It is evident that real residential prices fell more in states that implemented retail competition programs than in those that did not. Only Texas shows an increase in residential prices. However, in light of the discussion in the last section, if the lower prices in retail competition states are due to competition reforms they are a consequence of the negotiations over stranded cost recovery, regulated default service pricing, lower wholesale market and perhaps reforms in the regulation of distribution networks rather than retail competition per se. This must be the case because so few residential customers have switched from regulated default service to service provided by competitive retail suppliers. Indeed, the states with the largest reductions in real prices (Illinois and New Jersey) had almost no residential switching. Moreover, Texas has had the greatest success with getting residential customers to switch to competitive suppliers and is the only retail competition state to exhibit a significant increase in real residential prices during this period of time.

Figure 7 displays the same information for industrial prices. Here the results are more mixed. There is no consistent pattern in the trends in real industrial prices for states

[8] One important caveat to this and the analysis that follows should be noted. The retail price data may have imperfections. Reported retail price data ultimately rely on reports filed with the Energy Information Administration (EIA). It is fairly clear that it took some time for EIA to take full and appropriate account of the impacts of retail competition on the price data reported to them. However, by 2004 EIA seems to have solved these reporting problems so that the comparisons between 1996 prices before there was any retail competition and 2004 prices should be valid.

that implemented retail competition compared to those that did not. Indeed, real industrial prices fell more on average in states without retail competition than in those states that introduced it for industrial customers. States like Nevada and Montana introduced retail competition for industrial customers in a way that provided little protection from changes in wholesale market conditions, while other states provided hedged default service prices of varying durations and with varying terms and conditions. Moreover, the generation mix and the associated effects of fuel prices on generation costs, entry of unregulated generators, and changes in wholesale market conditions varies from region to region.

We can begin to analyze the impacts of wholesale and retail market reforms on electricity prices in different states using additional time series and cross-sectional data that measure these variables and allow us to control for various cost drivers. The following analysis is what I believe is the first, admittedly crude, empirical analysis to examine more systematically the effects of cost drivers and competitive policy reforms on retail prices across states and over time. I view it as more of a systematic data analysis exercise than an effort to estimate a complete model of retail prices. It is a starting point that I hope will lead to more refined analyses.

I have collected a state-level panel data set covering the period 1970 through 2003[9] that includes variables measuring residential and industrial retail prices, various cost drivers, and variables measuring the intensity of various "deregulatory" initiatives, starting with PURPA. The data are discussed in more detail in the Appendix. In the spirit of Stigler and Freidland (1962), I estimate the following price equation for residential and commercial customers using state-level data for the periods 1970 – 2003 and 1981-2003

[9] The data for some of the right hand side variables are not yet available for 2004. .

that include variables measuring cost drivers and those measuring the results of policy initiatives. The sample begins well before the introduction of the policy treatments so that the coefficients of the cost drivers should be well established.

$$P_{itj} = \beta_0 + \beta_1 RFC_{it} + \beta_2 HYDRO_{it} + \beta_3 NUCLEAR_{it} + \beta_4 RYield_t + \beta_5 SIZE_{it} \qquad (1)$$

$$+ \beta_6 PURPA_{itg} + \beta_7 EWG_{it} + \beta_8 RETAIL_{it} + \mu_i + \nu_t + \varepsilon_{it}$$

where:

i indexes states
t indexes years
j is either the residential price (r) or the industrial price (i)
μ_i is a state specific error
ν_t is a time specific error
ε_{it} is an iid random error

and the variables are defined as:

P: average retail residential or industrial price.

RFC: average real fossil fuel price per kWh of total electricity supplied in each state over time.

RYield: Real yield on electric utility debt over time.

HYDRO: share of total electricity supplied coming from hydroelectric generation in each state over time.

NUCLEAR: share of total electricity generation coming from nuclear plants in each state over time.

PURPA: share of total electricity generation coming from PURPA qualifying facilities (QF) in each state beginning with 1985.

EWG: share of electricity generated by unregulated generators in each state beginning in 1998.

RETAIL: a dummy variable indicating whether or not a state had Introduced retail competition in a particular year --- beginning in 1998.

Table 7 presents the regression results for this price model for residential prices for the period 1970 through 2003 using (1) generalized least squares, (2) state-specific fixed effects and (3) and state-specific fixed effects plus a time trend to correct for potential serial correlation. Table 8 presents the results for the same specifications for a shorter panel covering the period 1981-2003. Tables 9 and Table 10 present the same estimation results for industrial prices.

Let us look first at Tables 7 and 8 where the results for the residential price regressions are displayed. The results for the three alternative specifications and the two time periods are quite similar. For the residential price regressions the cost drivers generally behave as expected, recognizing that the fixed-effects regressions identify the coefficients from “within-state” variation over time. Increases in real fuel prices lead to higher retail electricity prices. More hydroelectric generation leads to lower retail prices. More nuclear capacity leads to higher retail prices reflecting the high capital costs of nuclear plants and their contribution to stranded cost recovery factors in states that introduced retail competition. Higher real interest rates also are associated with higher residential prices.

Turning to the policy variables, the more important is PURPA (QF) generation the higher are retail prices, consistent with the earlier literature (Joskow (1989)). The more important is unregulated wholesale market power supplies (EWG) the lower are retail prices. EWG generation has potential effects in both states with retail competition and those without it since EWG generation is a substitute for the generation a vertically integrated utility might produce from its own power plants. Note that there is substantial EWG generation in the Southeast where there is no retail competition. Finally, the coefficient on the retail competition dummy variable is consistently negative. The measured effect is that retail competition reduces retail prices on the order of 5% to 10% at the means of the sample.

Turning to Tables 9 and 10, the estimated relationships are generally similar for the industrial price equations as for the residential price equations. However, the retail competition effect, on the order of a 5% reduction in prices, is numerically smaller at the means of the sample and is estimated less precisely than for the residential price equations.

These results are consistent with the view that PURPA was bad for consumers from a retail price perspective, but that wholesale competition, captured with the EWG variable, and retail competition have both been associated with lower retail prices once the major input cost drivers are controlled for. These results must be interpreted with care, however. There are several caveats. First, the price data are likely to be imperfect. Reported retail price data ultimately rely on reports filed with the Energy Information Administration (EIA). It is fairly clear that it took some time for EIA to take full and appropriate account of the impacts of retail competition on the price data reported to them. To the extent that customers served by competitive retailers were excluded from the reports filed with EIA, the price data overestimate the actual prices realized by those customers who switched. To the extent that utility reports include only the delivery charges for customers who have switched, average prices may be underestimated. Second, several of the right hand side variables are not exogenous (though they change slowly). We know, for example, that retail competition was introduced in states with the highest retail prices and, other things equal, this would lead to an underestimate of the effect of retail competition. The long time series and the use of state-specific fixed effects should help to mitigate these problems, but not necessarily fully. Thus, further analysis to develop a more complete structural framework and relying on better data would be desirable.

6. CONCLUSION

The transition to competitive electricity markets has been a difficult process in the United States. In 1997 I wrote "[E]lectricity restructuring … is likely to involve both costs and benefits. If the restructuring is done right…the benefits … can significantly outweigh the costs. But the jury is still out on whether policymakers have the will to implement the necessary reforms effectively" (Joskow (1997), p. 136). I believe that statement continues to be true today. Creating competitive wholesale markets that function well is a significant technical challenge and requires significant changes in industry structure and supporting institutional and regulatory governance arrangements. It requires a commitment by policymakers to do what is necessary to make it work. That commitment has been lacking in the U.S. The major barrier to a successful restructuring and competition program in the U.S. at the present time is political. Many of the technical problems associated with creating well functioning competitive electricity markets have been solved, often through bitter experience. While FERC has been a leader in promoting competitive markets, the Bush administration and the Congress have provided tepid support at best. Political compromises over restructuring, conflicts between federal and state regulations, the mixing of states with and without competition programs, the absence of a strong pro-competition policy and associated statutory authorities coming from the Congress and advanced by the President have all worked to make successful reforms extremely difficult.

Despite these difficulties, considerable progress has been made and many useful lessons have been learned. There is growing evidence that competition can lead to cost and price reductions if policymakers will support the regulatory and institutional changes needed to allow competitive market forces to work. However, the creation of competitive market forces has also encountered some significant and costly problems and it is important that policies reflect the lessons learned from this experience. My interim assessment is that the glass is half full rather than half empty at the present time. I take this view based on the evidence of performance improvements and because the revisionist history about the "good old days of regulation" has conveniently ignored the $5000/Mw nuclear power plants, the 12 cent/kWh PURPA contracts, the wide variations across utilities in the construction costs and performance of their fossil plants, and the cross-subsidies buried in regulated tariffs that characterized the regulatory regimes in many states. As we look at the costs and benefits of competition we should not forget the many costly problems that arose under regulation.

Looking at the maps in Figure 1 and Figure 3 it seems clear that about half of the country is focused on moving forward with pro-competition policies, at least at the wholesale level, and half is not. Going forward I suspect that we will see a sort of contest between the performance of the regulated monopoly framework and the competitive market framework for governing the electric power sector in the U.S. With continuing analysis of comparative performance of alternative institutional arrangements we will be able to determine more definitively what is the best that we can do in an imperfect world.

TABLE 1

INDEPENDENT SYSTEM OPERATORS AND ORGANIZED WHOLESALE MARKETS 2005

System Operator	Generating Capacity (MW)
ISO-New England (RTO)	31,000
New York ISO	37,000
PJM (expanded) (RTO)	164,000
Midwest ISO (MISO)	130,000
California ISO	52,000
ERCOT (Texas)	78,000
Southwest Power Pool (RTO)[1]	60,000
ISO/RTO TOTAL	552,000
TOTAL U.S. GENERATING CAPACITY	970,000

Source: Individual ISO web pages, trade press reports and U.S. Energy Information Administration (EIAa and EIAb), various issues.

[1] Organized markets being developed.

TABLE 2

NEW U.S. GENERATING CAPACITY
MW

YEAR	CAPACITY ADDED (MW)
1997	4,000
1998	6,500
1999	10,500
2000	23,500
2001	48,000
2002	55,000
2003	50,000
2004	20,000
2005 (through May)	2,000
TOTAL	220,000 Mw

Source: U.S. Energy Information Administration (EIAa and EIAb), various issues.

TABLE 3

DAY-AHEAD NODAL PRICES IN NEW ENGLAND
July 19, 2005, Hour 17
Load Zone Averages
$/MWH

Load Zone	Average Hour Price
Maine	$130.56
New Hampshire:	$159.34
Vermont:	$195.65
Massachusetts (NE):	$321.55
Massachusetts (SE):	$162.12
Massachusetts (WC):	$161.14
Rhode Island:	$142.44
Connecticut:	$165.96

Source: ISO New England Hourly Price Data Archive

TABLE 4

AVERAGE REAL TIME ELECTRIC ENERGY PRICES IN NEW ENGLAND
ADJUSTED FOR FUEL PRICE CHANGES
$/MWH

YEAR	ACTUAL	ADJUSTED FOR FUEL PRICES
2000	$45.95	$45.95
2001	48.60	43.03
2002	46.55	37.52
2003	53.40	43.51
2004	54.44	43.33

Source: ISO-New England *Annual Markets Report for 2004* (2005)

TABLE 5

THEORETICAL NET ENERGY AND ANCILLARY SERVICES REVENUE FOR A NEW COMBUSTION TURBINE PEAKING PLANT
PJM
$/MW-YEAR

YEAR	*Net* Energy and Ancillary Service Revenue
1999	$64,445
2000	18,866
2001	41,659
2002	25,622
2003	14,544
2004	10,453
AVERAGE	$ 29,265/MW-year

Annualized 20-year Fixed Cost ~ $70,000/Mw/year

Source: *PJM State of the Market Report for 2004* (2005).

TABLE 6

RETAIL COMPETITION IN MASSACHUSETTS
February 2004 and May 2005

Retail Choice Began March 1998

Customer Type	% of Load Served by ESPs	
	February 2004	May 2005
Residential	2.6%	6.1%
Small Commercial/Industrial	10.8%	19.3%
Medium Commercial/Industrial	17.0%	22.2%
Large Commercial/Industrial	48.3%	63.3%
TOTAL	22.6%	34.0%

Source: Massachusetts Department of Energy Resources, July 2005

TABLE 7
RESIDENTIAL PRICE EQUATIONS
1970-2003
(standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.51	0.51	0.48
	(0.019)	(0.019)	(0.019)
HYDRO	-0.20	-0.16	-0.36
	(0.077)	(0.095)	(0.099)
NUCLEAR	0.39	0.38	0.45
	(0.054)	(0.056)	(0.056)
YIELD	0.042	0.043	0.47
	(0.002)	(0.002)	(0.002)
SIZE	-0.13	-0.13	-0.11
	(0.0048)	(0.00048)	(0.0063)
PURPA	0.43	0.42	0.61
	(0.078)	(0.079)	(0.084)
EWG	-0.24	-0.23	-0.23
	(0.058)	(0.058)	(0.057)
RETAIL	-0.24	-0.25	-0.21
	(0.042)	(0.042)	(0.042)
R^2 (corrected)	0.74	0.61	0.62

TABLE 8
RESIDENTIAL PRICE EQUATIONS
1981-2003
(standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.24	0.19	0.048
	(0.031)	(0.032)	(0.029)
HYDRO	-0.064	-0.125	-0.36
	(0.11)	(0.153)	(0.137)
NUCLEAR	0.21	0.136	0.082
	(0.071)	(0.073)	(0.056)
YIELD	0.06	0.06	0.027
	(0.0046)	(0.0047)	(0.004)
SIZE	-0.18	-0.21	-0.0001
	(0.0077)	(0.0088)	(0.0089)
PURPA	0.22	0.122	0.288
	(0.09)	(0.092)	(0.082)
EWG	-0.19	-0.16	-0.16
	(0.054)	(0.054)	(0.048)
RETAIL	-0.24	-0.25	-0.126
	(0.039)	(0.038)	(0.034)
R^2 (corrected)	0.66	0.73	0.79

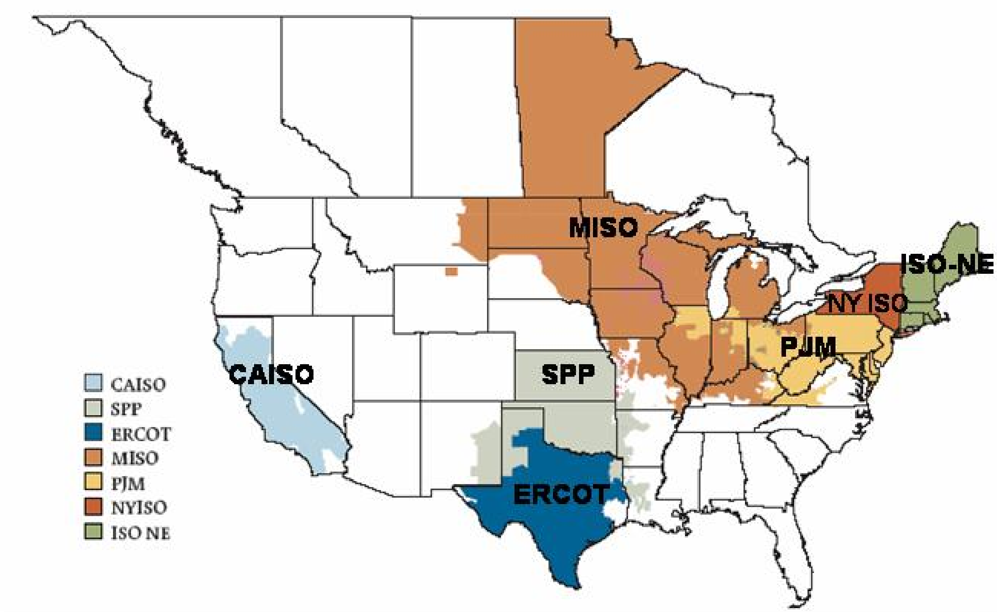
TABLE 9
INDUSTRIAL PRICE EQUATIONS
1970-2003
(standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.74	0.73	0.68
	(0.019)	(0.02)	(0.019)
HYDRO	-0.264	-0.13	-0.535
	(0.078)	(0.10)	(0.10)
NUCLEAR	0.20	0.22	0.42
	(0.071)	(0.055)	(0.056)
YIELD	0.034	0.034	0.043
	(0.0054)	(0.002)	(0.002)
SIZE	-0.4	-0.4	-0.3
	(0.034)	(0.04)	(0.03)
PURPA	0.41	0.38	0.69
	(0.08)	(0.081)	(0.083)
EWG	-0.26	-0.24	-0.22
	(0.059)	(0.059)	(0.057)
RETAIL	-0.16	-0.17	-0.12
	(0.043)	(0.043)	(0.042)
R^2 (corrected)	0.62	0.60	0.64

TABLE 10
INDUSTRIAL PRICE EQUATIONS
1981-2003
(standard errors in parenthesis)

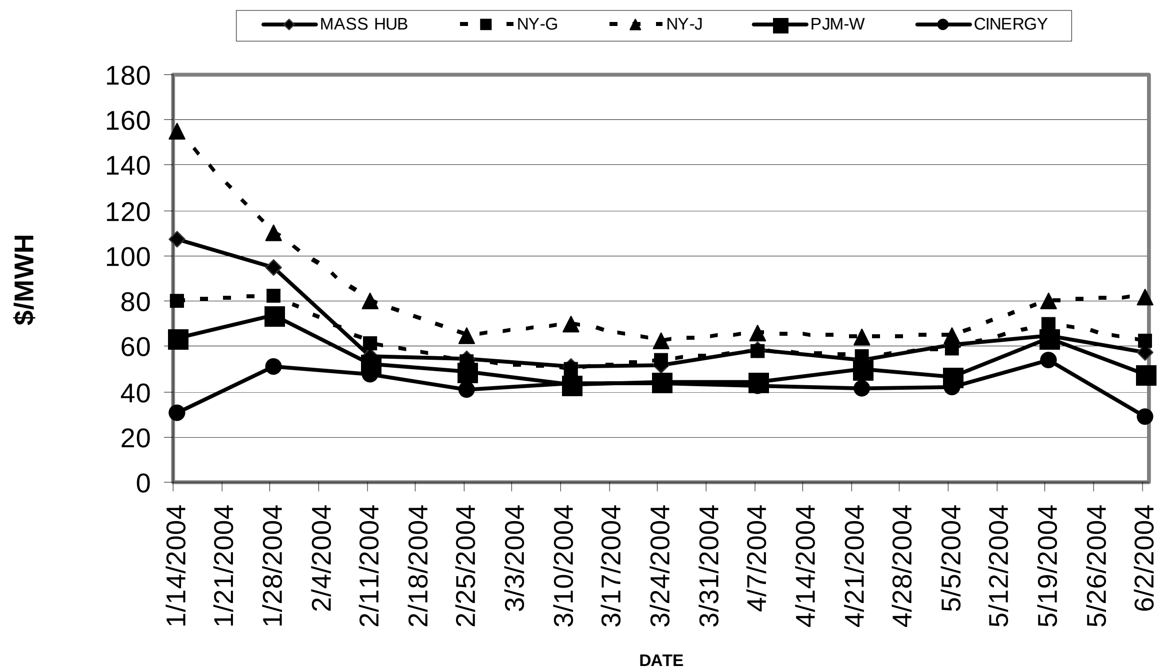
Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.53	0.48	0.23
	(0.03)	(0.031)	(0.026)
HYDRO	-0.40	-0.29	-0.62
	(0.10)	(0.15)	(0.12)
NUCLEAR	0.11	0.056	0.029
	(0.071)	(0.075)	(0.057)
YIELD	0.078	0.079	0.029
	(0.0045)	(0.004)	(0.004)
SIZE	-0.4	-0.4	-0.3
	(0.04)	(0.04)	(0.03)
PURPA	0.24	0.10	0.18
	(0.09)	(0.09)	(0.072)
EWG	-0.24	-0.23	-0.15
	(0.054)	(0.055)	(0.042)
RETAIL	-0.18	-0.20	-0.043
	(0.039)	(0.039)	(0.03)
R^2 (corrected)	0.61	0.68	0.82

Figure 1: ISOs and RTOs in the United States 2005



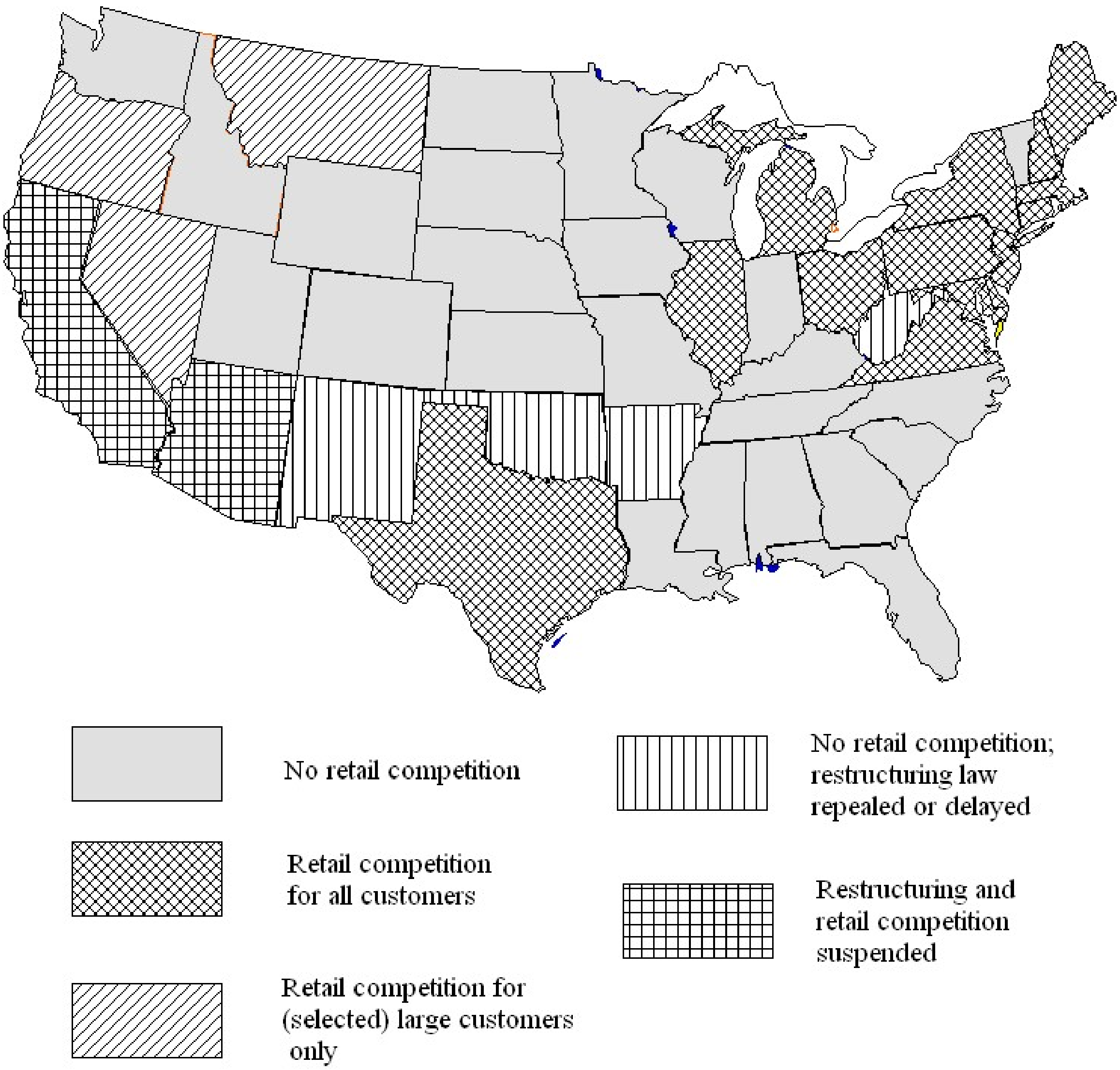
Source: U.S. Federal Energy Regulatory Commission (2005), p. 52

Figure 2: Day-ahead Peak Period Prices (2004) $/MWH



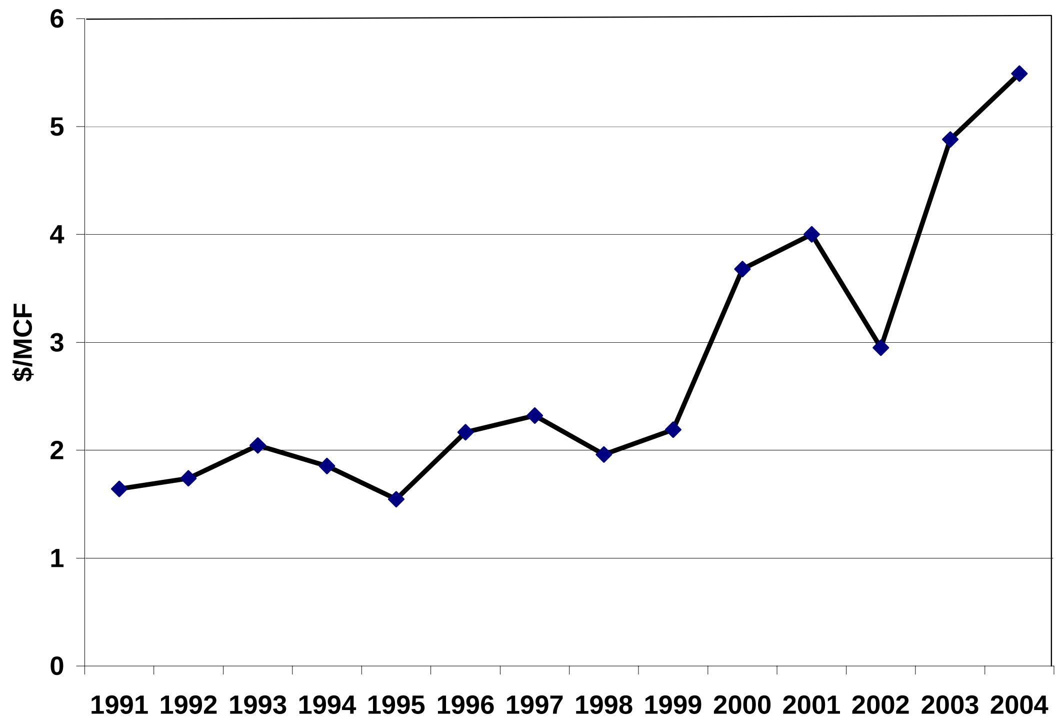
Source: *Megawatt Daily*, The McGraw-Hill Companies, (various issues)

Figure 3: Status of retail competition and restructuring reforms 2005



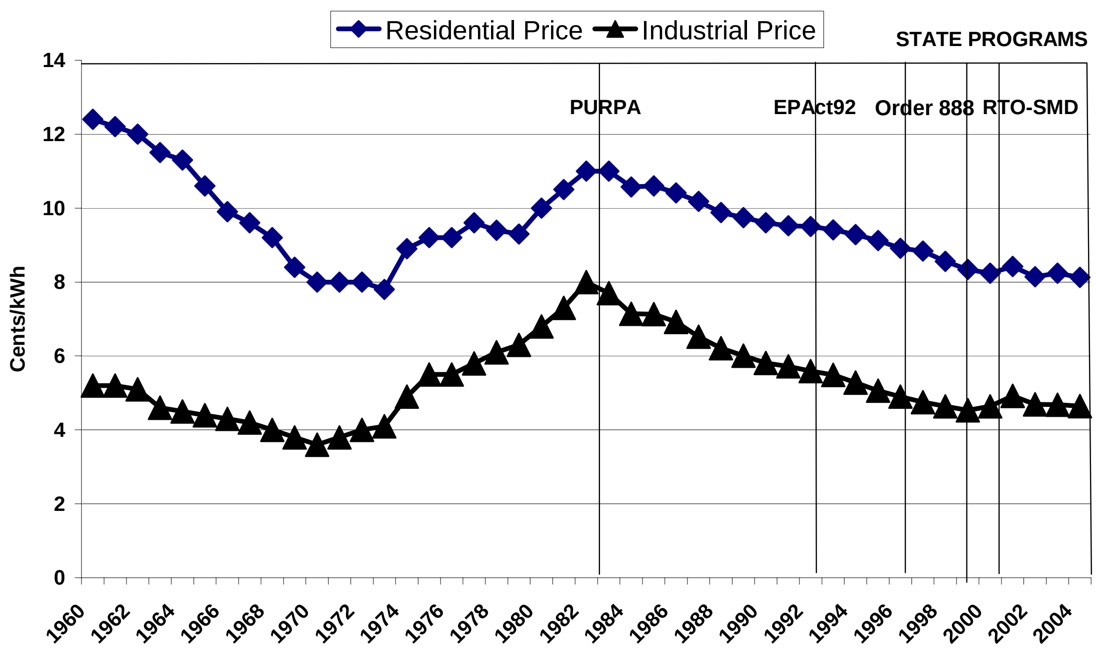
Source: Author’s assessments

Figure 4: Average natural gas wellhead prices 1991-2004, $/MCF



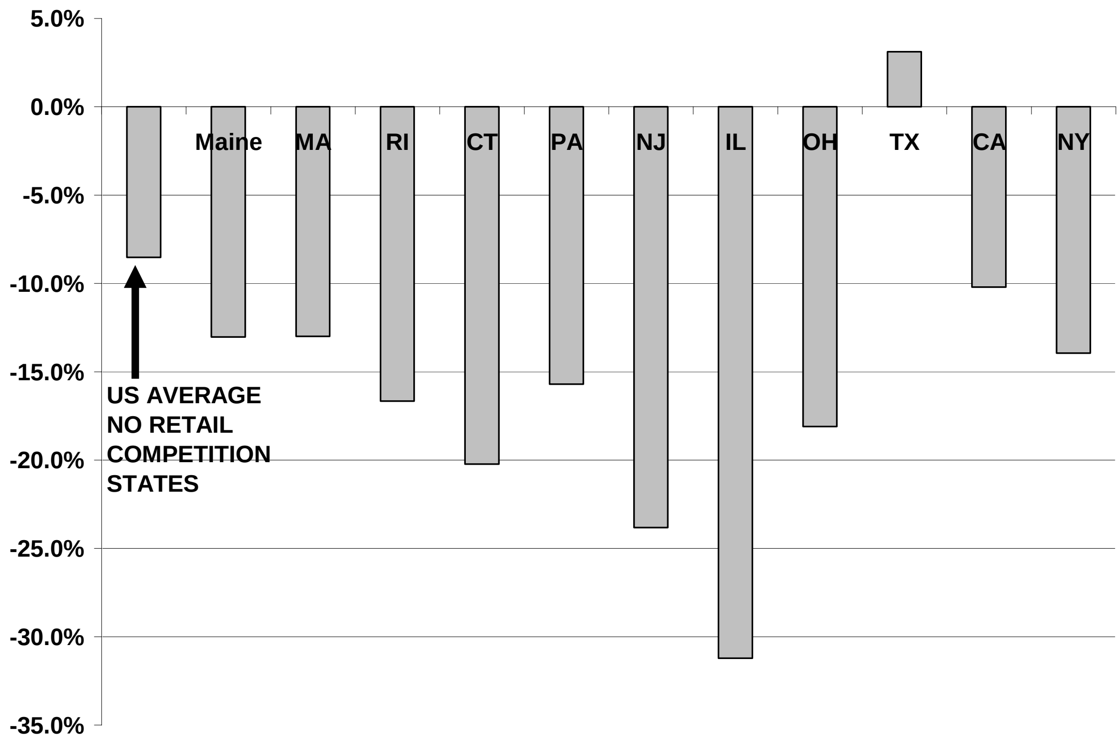
Source: U.S. Energy Information Administration (EIAc, EIAd) (various issues)

Figure 5: Average real U.S. electricity prices 1960-2004 ($2000)



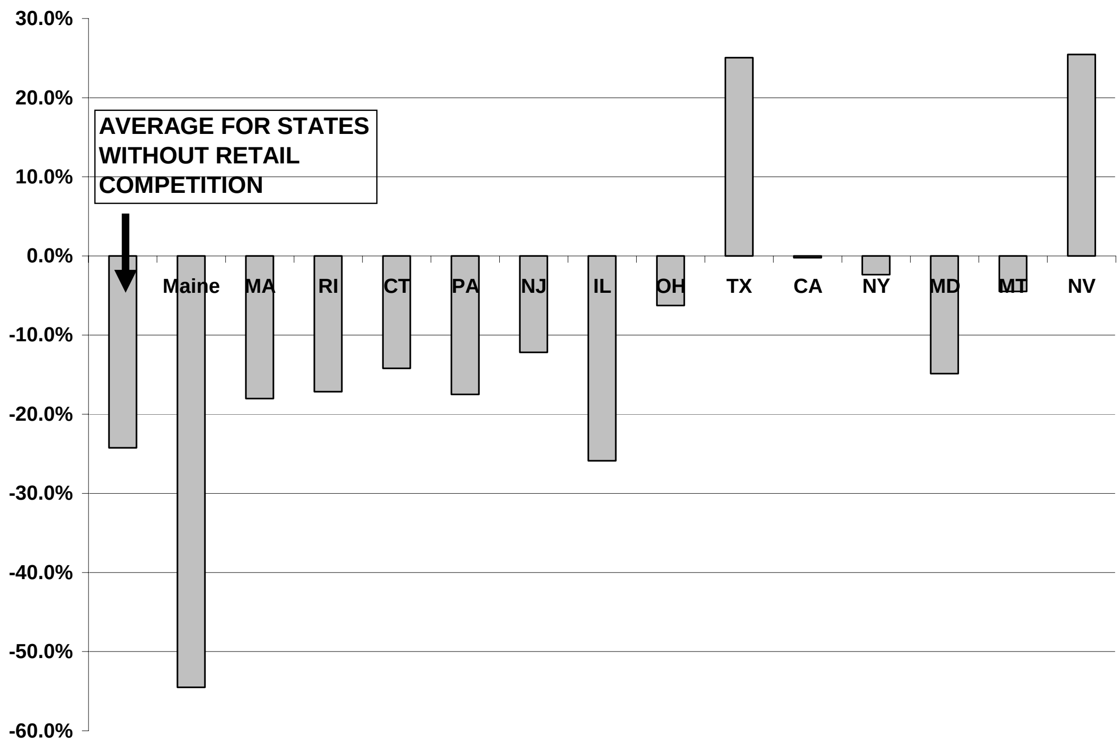
Source: U.S. Energy Information Administration (EIAd, EIAa) (various issues**),** nominal prices adjusted using the GDP deflator

Figure 6: Changes in real residential prices with and without retail competition 1996-2004 (%)



Source: Calculated from U.S. Energy Information Administration (EIAa, EIAb, EIAd) (various issues), adjusted for changes in the consumer price index.

Figure 7: Changes in real industrial prices 1996-2004 with and without retail competition (%)



Source: Calculated from U.S. Energy Information Administration (EIAa, EIAb,EIAd) (various issues), adjusted for changes in the Consumer Price Index.

DATA APPENDIX

State-level data from 1970 through 2003 were used to estimate the regression coefficients for equation (1) as reported in Tables 7, 8, 9 and 10. Maryland and the District of Columbia have been combined for all years due to the sources' combined data presentation in several years. Idaho was dropped due to data imperfections. Data construction becomes challenging after 1997 as a result of divestiture of utility plants, entry of EWGs and spread of retail competition. EIAa, EIAb, EIAc are used extensively to fill gaps in EEIa and EEIb.

Retail electricity prices: Retail prices are measured as average revenue per kWh sold to residential and industrial customers respectively for total electric power industry by state. These data include municipal and cooperative distribution companies. EEIa, EIAa, EIAb, EIA (2005).

Average fuel cost (adjusted for changes in CPI with 1970 = 1): Average real fuel cost per kWh of electricity generated in each state, including by independent power producers after 1997. EEIa, EIAa, and EIA (2005).

Hydro electric generation share: Fraction of total electricity generated in each state accounted for by hydroelectric generating capacity. EEIa and EIA (2005).

Nuclear generation share: Fraction of total electricity generated in each state accounted for by nuclear generating plants. EEIa and EIA (2005).

PURPA generation share: Estimate of fraction of total electricity generated in each state accounted for by PURPA Qualified Facilities. Series starts in 1986. MWh of PURPA generation assumed constant after 1997. EEIb and EIA (2005). Overlap years are averaged.

EWG generation share: Eastimate of fraction of generation in each state accounted for by unregulated generators, excluding PURPA generators. Series starts in 1998. EIA (2005).

Real bond yields: *Moody's* average yield on electric utility bonds minus the annual rate of inflation in consumer prices (CPI).

Average residential and industrial kWh consumption per customer: Average consumption per retail customer for residential and industrial customers for the total electric power industry by state. EEIa, EIAa, EIAb, EIA (2005).

Retail competition: Dummy variable = 1 if retail competition. Author's assessments based on programs initiated in each state. First retail competition program 1998. California is treated as having retail competition beginning in 1998.

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