A Cautionary Tale: U.S. Electricity Sector Reform

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In the 1970s, the U.S. electric utility industry was faced with rising costs and sluggish demand. Efforts at lowering costs and revitalizing the industry through competition have largely been disappointing. Consumers have not seen prices fall, except where regulators have intervened. The merchant sector has suffered a financial crisis, hurting competition in both wholesale and retail markets. Advocates for deregulation assert that minor changes to market rules and regulations will yield the benefits promised. We argue that things are not so simple. Successful deregulation requires markets to be competitive and complete, neither of which is true in the U.S. Creating competitive markets is not impossible, but doing so imposes costs on the system which may outweigh the benefits of deregulation.

Introduction

Reform of the electric power sector in the United States was supposed to usher in a new era of dynamic competition. Instead, the industry finds itself in an uncomfortable stasis, unsure whether to move forwards or backwards. The Federal Energy Regulatory Commission (FERC) continues to push for further reforms, while others believe that the current form of restructuring should be abandoned altogether[2]. Policymakers in the U.S. are currently arguing over details; they appear to believe that minor adjustments will yield the benefits promised to consumers and the industry.

As we have previously argued [Lave, Apt and Blumsack 2004], things are not that simple. In particular, policymakers have failed in three key areas in reforming the U.S. electric power industry. First, they have failed to succinctly define the goals of restructuring. Deregulation and commoditization appear to be venerated as policy goals, rather than the means by which the goals are met. Second, while policymakers have realized that regulation is by no means perfect, they have failed to appreciate that competition in electricity cannot be perfect either. Most appear to believe that problematic regulation can be replaced with seamless competition; we believe a more realistic tradeoff is between imperfect regulation and imperfect competition. Finally, policymakers and academics alike seem to have forgotten the old maxim that there is no free lunch. Moving from a highly regulated electric power industry to one based on markets imposes costs, and the costs involved in establishing, promoting, and monitoring markets have proven to be quite high in the U.S., particularly in comparison to the benefits thus far.

Policymakers in countries (particularly developing countries) considering a competitive electricity-market model should take a hard look at the challenges faced by the United States, and think carefully about the underlying goals of electric sector reform. In particular, will competition serve as an aid or impediment to achieving the stated goals? What costs would be involved in the transition to a competitive market structure? In this paper, we describe the U.S. experience with electricity restructuring and attempt to contrast the path taken by the U.S. with our view of the discussion policymakers should be having in countries considering electric-sector reform.

The Electric Power Industry in the United States: From Competition to Regulation and Back Again

Most electric-utility customers in the United States (except those in municipal co-operatives or public power districts) have never known anything except the vertically-integrated monopoly provider, regulated on a state-by-state basis. Up until restructuring laws took effect in the mid 1990s, the electric utility industry had not seen any radical changes in organization for over eighty years. As a result, the utility business could have been variously described as stable (if you were an investment manager choosing stocks for widows and orphans) or dull (if you were a recent business-school graduate looking for a high-flying career). Things were not always this way. The electric utility industry emerged in the late 1800s, alongside the oil industry. Far from being stable or dull, the early decades of the U.S. electric power industry were marked by intense competition, corruption, and monopolization.

The Era of Competition, 1880 - 1910

The birth of the U.S. electric power sector came with the opening of Thomas Edison's Pearl Street generation station in New York City's financial district in 1882. Fifteen years later, George Westinghouse demonstrated high-voltage transmission of alternating current (AC) power, and fierce competition between Westinghouse's AC power and Edison's DC power developed rapidly. In the end, the AC model won out, but led to a rather chaotic competition as numerous electric-power companies built redundant infrastructure, attempting to compete for the same customers [van Vactor 2004]. One of the few utility pioneers who realized the costly nature of this competition was Samuel Insull, who believed that efficiency (then 1/10th of what it is now) would rise with the construction of larger power plants. Insull had several large steam turbines built, and his Chicago Edison company soon drove its rivals out of business; his utility empire would soon expand to neighboring areas. Predictably, consumers suffered, prompting the New York Public Service Commission to write in 1908, "That competition cannot be depended upon to protect the consumer from high prices and poor service has been fully demonstrated" [Maltbie 1908].

The Utility Consensus, 1910 - 1970

Ironically, the oligopoly utilities saw themselves as vulnerable to competition. Utility managers, Insull included, pleaded for some sort of regulation to save the electric utility monopolies from "ruinous" competition and consequent high capital cost [Hirsch 1999: 406; van Vactor 2004]. By 1910, the "natural monopoly" consensus had emerged [Hirsch 1999: 406]. Vertically-integrated electric utilities would be given monopoly rights over a certain geographic area, and in return the utilities would allow their prices and profits to be regulated. The utility compact proved to be a convenient arrangement for the monopolists; the steady stream of profits guaranteed by regulators was attractive

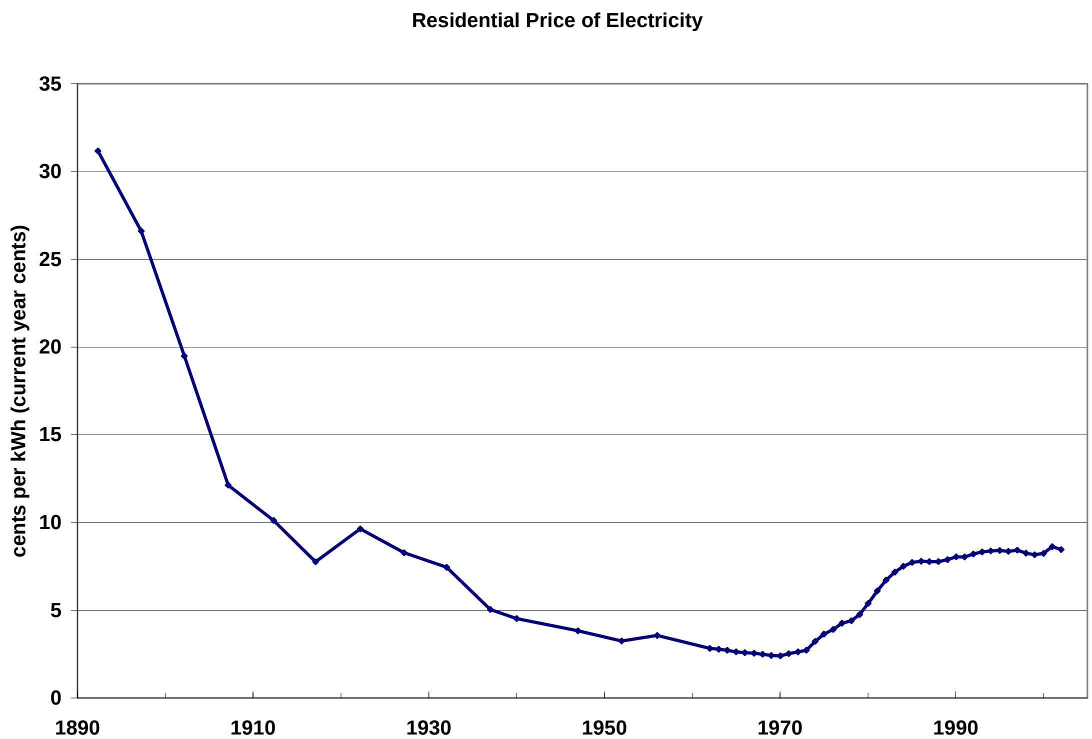

Figure 1: Residential Price of Electricity in the United States, in current-year cents per kilowatt-hour. ***Source:*** *Morgan et. al. 2005.*

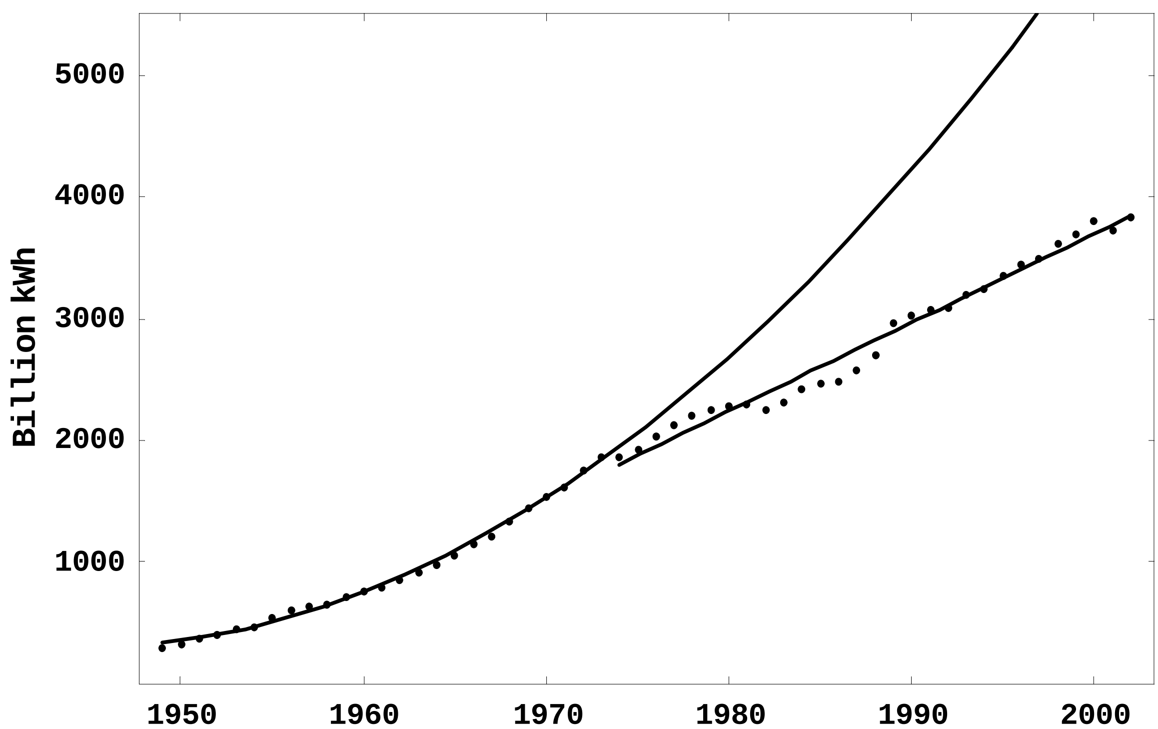

Figure 2: U.S. Electricity Sales, All Sectors, 1950 – 2002. The dotted line represents actual sales, while the solid lines represent the exponential trend and the shift to linear growth beginning in 1973. ***Source:*** *Morgan, et. al. 2005*

to bankers, who stood ready to lend enormous sums to the industry and Insull in particular. Unsurprisingly, corruption was also rampant in the industry, with bribery of regulators and state legislators becoming a common occurrence [McDonald 1962].

The Era of Reform, 1970 – 2001

In many countries, the impetus for electricity industry reform was the privatization of previously nationalized utilities. As many consumers in the U.S. have historically been served by privately-owned electric utilities, regulatory reform in the U.S. was not primarily aimed at disrupting the existing industrial structure. First and foremost in the minds of policymakers was cost control [de Vries 2004: 353]. Figure 1 shows the retail price of electricity in the United States for the residential sector from the 1800s through 2002. Up until the 1970s, power prices generally fell every year with few exceptions. The trend reversed itself beginning in 1973 with the Arab oil embargoes; power prices in the U.S. have been rising ever since, amid utility investments in costly and unreliable large-scale nuclear and fossil-fuel plants[3] [Christensen and Greene 1976; Morgan et. al. 2005]. At the same time as costs (and prices) were rising, the growth in demand unexpectedly began to slow considerably after the oil embargo, as shown in Figure 2. Costs aside, stagnating demand alone turned many utility investments into “white elephants,” and electricity prices had nowhere to go but up.

Regulators were loath to force the utilities to cut costs, since they would be blamed if reliability of the electric grid were to suffer. They also could not keep prices down, since the utility compact guaranteed rates of return. At the same time, a wave of deregulation had swept through several other U.S. industries such as trucking, airlines, natural gas, and crude oil [Blumsack, Perekhodtsev and Lave 2002; van Vactor 2004]. Many policymakers believed that the same strategy could work in the electricity industry, and thus the Public Utility Regulatory Policies Act (PURPA) was passed by the U.S. Congress in 1978. Prior to PURPA, only regulated utilities could own and operate power plants. PURPA paved the way for unregulated independent power producers (IPPs) to begin operating in the United States, and forced electric utilities to purchase energy from these IPPs under long-term contracts. However, most IPPs generated electric power from less-commercialized technologies that were much more expensive than fossil fuels[4]. In either case, the contract prices were very high, and one effect of PURPA was ultimately to keep prices high even after the energy crisis had died down.

In 1992, Congress expanded the field of eligible players in the electric power industry with the passage of the Energy Policy Act (EPAct). The EPAct allowed for unregulated IPPs that did not have long-term contracts. These generators would simply be allowed to generate electricity and sell it to traditional utilities at whatever price the market would bear. Hoping to promote risk management and competition in electricity the same way that it had developed in natural gas and crude oil [de Vany and Walls 1993; van Vactor 2004], the EPAct also allowed for the wholesale trading of electric power as a commodity. Brokers and marketers (who may or may not have owned any physical assets) were now allowed to buy and sell electricity. Bilateral trading for bulk power began in earnest, particularly in the Western U.S.[5] [van Vactor 2004].

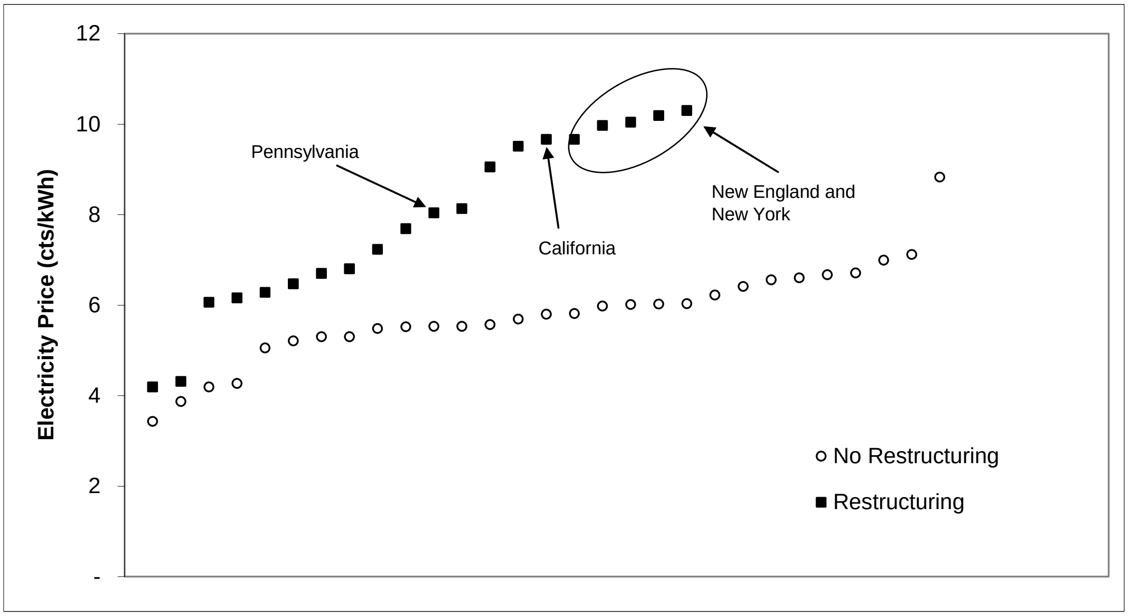

Figure 3: Average Electricity Prices for Restructured and Regulated States, 1992. Each point in the figure represents one state; Alaska and Hawaii are excluded. Prices are weighted averages over all sectors of the electricity industry. ***Source:*** *Energy Information Administration 2000; 2004.*

Neither PURPA nor the EPAct was able to successfully bring down electricity prices. Two states, California and Pennsylvania, decided to take more drastic measures to promote competition. Among other measures, both states established centralized spot markets for electricity (Pennsylvania's market was actually part of a larger regional market known as the Pennsylvania-New Jersey-Maryland Interconnection, or PJM), and both opened retail markets to competition, allowing individual customers to choose their electricity supplier. The PJM market design has, thus far, proven quite successful in terms of keeping prices low. California's experience was exactly the opposite: after two years of operating reasonably smoothly, prices exploded in the summer of 2000. Two of California's three investor-owned utilities (IOUs) ran out of money to pay for electricity, triggering a second power crisis which lasted well into 2001, forcing the State to buy electricity directly. California's consumers are now saddled with a debt of $40 billion and long-term electricity contracts priced at multiple times the current market price.

The primary impetus for electricity reform was cost. While electricity costs rose throughout the U.S. during the 1970s, they did not do so uniformly. It is not surprising that the pioneers of electricity deregulation, California and Pennsylvania, had electricity prices 45% and 20% above the national average when the EPAct was passed in 1992. Figure 3 shows the decision of each state to restructure or remain regulated and the price of electricity in that state in 1992. Those states which pursued restructuring most aggressively (California and nearly the entire Northeast) also had the highest prices. The states which did not pursue any sort of restructuring can be broadly divided into two groups. The first is those states with abundant resources of low-cost fuel, such as hydroelectric in the Pacific Northwest and coal in the Southeast. The second group of states which chose not to deregulate largely represent sparsely-populated (and agricultural) areas of the Midwest, where demand centers are not large or concentrated enough to support competition.

Where Now? 2001 – Present

California's power crisis should have forced policymakers and economists to ponder how far reforms could be pushed in the electric power sector. Instead, they pondered what form restructuring should take. The response of the Federal Energy Regulatory Commission (FERC) was a proposal known as the Standard Market Design (SMD), which would have forced the entire U.S. to develop electricity markets strikingly similar to those operated by PJM. Over several years, enough opposition was raised to various provisions of SMD that FERC formally withdrew the proposal in July 2005.[6] In the meantime, the entire Northeastern U.S. adopted a market structure similar to PJM, and PJM itself began expanding beyond its original territory to include the operating areas of several Midwestern and Southeastern utilities.

We will return to the question that policymakers should be asking at the end of the paper, where we will provide a list of issues that policymakers from any country should address before proceeding with further reforms. Our next task is to describe in more detail the types of reforms enacted in the various states which chose the path of restructuring, and how those states have fared.

"Deregulation" or "Restructuring?"

Although electricity reform in the U.S. happened largely on a state-by-state basis, all restructuring plans have shared a number of common traits. Most electric-sector reforms at the state or regional level have included most, if not all, of the following components:

1. Vertical dis-integration of the generation, transmission, and distribution businesses of regulated utilities. In some places, dis-integrated was brought about through explicit divestiture, while in other places a "Chinese Wall" has been erected, limiting flows of information between different parts of the business.

2. The creation of centralized hourly spot markets for wholesale electricity, ancillary services, and capacity.

3. The designation of a single entity to manage regional transmission grids and (often times) to operate the hourly spot market. These entities are known as Independent System Operators (ISO) or Regional Transmission Organizations (RTO).

4. Introduction of retail competition, where individual consumers are required to choose between the utility and a third-party supplier for their electric generation needs. Although the purchase of generation is open to competition, distribution (delivery to ultimate consumers) has typically remained regulated. In some states, retail competition has been limited to large industrial customers.

5. Utilities have been given some provision to recover "stranded costs" – debts incurred during the regulated era which would make the utility unable to compete in the deregulated era. Debts remaining from investments in nuclear power plants and PURPA contracts are often included in a utility's stranded costs.

Individual states have not been entirely free to design their own reform programs. FERC Order 888, passed in 1996, required that all transmission owners provide non-discriminatory access to their transmission lines; this rule appears to have been aimed at promoting interregional trade between the Southeastern U.S., which has the lowest power prices in the country, with the Northeastern U.S., which has some of the highest prices in the country. FERC Order 2000, passed in 2000, required all transmission owners to form or join an RTO. While most areas appear to be compliant with the open-access directive under Order 888, the formation of RTOs has been somewhat slower. At this point, the entire northeastern U.S. and the Midwest have FERC-approved RTOs. Texas and California have ISOs which operate nearly identically to RTOs, but have not been approved by the FERC[7]. These RTOs represent less than half of the geographic area of the United States (excluding Alaska and Hawaii), and approximately two-thirds of U.S. demand [Morgan et. al. 2005; Krellenstein 2004].

Wholesale Market Reforms

While regulatory reform has largely taken place at the state level, most market and RTO activity has taken place on a regional level. The precise design of the RTO has varied from region to region, but nearly all RTOs have been charged with serving as market makers, market monitors and grid operators. The RTO bears responsibility for matching supply and demand, managing congestion on the grid, and procuring ancillary services when necessary.

Regional differences in RTO operating procedures are largely due to historical influences. RTOs in the Northeast (PJM, NYISO, and ISO-NE) all rose out of "tight" power pools [van Vactor 2004], in which a number of utilities agreed to coordinate generation and grid operations[8]. As such, the three Northeastern RTOs operate very similarly to each other and coexist with an active bilateral and long-term market for electricity. The portion of the grid managed by ERCOT is physically separated from the rest of the U.S. power grid, with very limited interconnection. ERCOT is the only active RTO in the U.S. which does not operate any sort of centralized spot market; Texas' power market is based entirely around bilateral transactions. That Texas' RTO model is quite different from the rest of its counterparts is therefore not surprising; ERCOT's operations more closely resemble natural gas markets in Texas than electricity markets in other parts of the U.S. In many ways, California's model was the most innovative; it certainly represented the most dramatic break from the past[9]. Prior to restructuring, the Western Systems Power Pool (WSPP) functioned very similarly to the Texas market, being based entirely around bilateral trading. California broke with the WSPP by prohibiting its three large IOUs from engaging in bilateral transactions. In particular, the IOUs could not sign long-term contracts for electric energy[10]. Independent generators, meanwhile, were free to participate in California's energy markets or take their business to neighboring states (or not operate at all, as many plant owners appeared to do).

The RTO's centralized spot market is in some ways the centerpiece of restructuring in the U.S. Nearly every RTO operates an hourly auction for energy, while none operate a long-term market for energy. Under the regulated regime, vertically-integrated utilities would serve load by dispatching power plants on a least-cost basis. The key difference in the RTO's spot markets is that the RTO carries out this economic dispatch based on the generator bids into the hourly auction. California's spot market was unique in that the responsibility for running the market was split between two entities. The hourly energy auction was run by the state's RTO, the California Independent System Operator (CAISO), while a separate day-ahead energy auction was run by the California Power Exchange (PX). Unlike the CAISO, which in addition to running the hourly energy auction also had to perform the other tasks of an RTO, the sole function of the California PX was to run a day-ahead wholesale power market.

The grid-operator role of the RTO is more complicated. The fragile nature of the power grid requires not only that supply and demand are constantly kept in balance, but that frequency and voltage magnitudes stay reasonably constant everywhere in the grid. Such stability concerns require that frequency deviations in the grid be less than 1%; there is a little more tolerance regarding voltage, where power engineers have historically kept voltage magnitudes from varying more than 5% above or below system norms.

In the commoditized electric power industry, one of the largest sources of uncertainty arises from transmission congestion. Since AC power networks suffer from the problem of loop flows, power injections at one point in the grid affect the entire network, sometimes in unpredictable ways (for examples of counterintuitive flows, see Kirschen and Strbac 2004). Transmission congestion increases costs on the network by forcing the grid operator to alter the economic dispatch, increasing power output from more-expensive generators. RTOs have attempted to internalize the congestion externality through some form of locational pricing; price differences between zones or nodes would signal market participants to congestion in the network, giving them incentives to alter their schedules in order to avoid paying higher prices on the congested lines[11] [Hogan 1992].

Simply pricing congestion does not itself solve the uncertainty problem since prices cannot be accurately calculated until after power injections actually take place. A participant in an electricity market, therefore, does not *ex ante* know if she has scheduled power to be injected into a congested line. RTOs have tried two distinct approaches to help participants manage congestion risk. The first approach, tried only by the California ISO, was a two-stage bidding process; participants would first bid for energy and then for the right to use congested lines. The second approach, favored by all other U.S. RTOs (and eventually adopted by California following the power crisis), was the use of a financial instrument known variously as a financial transmission right (FTR) or a transmission congestion contract (TCC). The holder of an FTR receives a payment equal to the price difference between the two points specified in the FTR. Although the original proponents of FTRs claimed that their use would encourage efficient levels of transmission investment [Hogan 1992; Bushnell and Stoft 1996], time has revealed the true usefulness of FTRs as hedging instruments.

To ensure equilibrium between supply and demand, and also to ensure that the grid operates within its prescribed voltage and frequency limits, RTOs have established markets for "ancillary services" – a broad class of power plant operations beyond the simple generation of electric energy. Three types of products comprise the RTO ancillary services markets. The first, known as regulation reserves, represents automatic generation control (AGC) measures intended to maintain the 60-Hertz frequency of the electric grid[12]. The second type, known as spinning reserves, are provided by generating units with quick ramp rates in order to make up for very short-term deviations between the supply and demand of electric energy. The third type of ancillary service, known as black-start capability, is offered by generating units that can re-energize the grid following blackouts.

A fourth type of ancillary service, distinct from the others in that it is currently not procured through markets even in RTO territories, is known as voltage support. Consumer goods which require motors (such as air conditioners) have much larger reactive power requirements than, say, light bulbs. On peak-demand days during the summer, this increased reactive power requirement can cause the voltage to drop below acceptable levels and hence voltage support is required to keep the electric grid within prespecified voltage limits. Voltage support can be supplied by power plants through the production of reactive power, or from standalone devices such as capacitors. The technical challenge in providing voltage support is that reactive power attenuates quickly with distance and therefore must be supplied close to the point of consumption. Although industry standards state that individual utilities have the responsibility to monitor and correct voltage problems, whether these ancillary services are the responsibility of utilities or RTOs has been the subject of much debate, particularly after the August 2003 blackout.

The Northeastern RTOs are also responsible for several other services aimed at promoting reliability in the electric grid and efficiency in its energy markets. The RTOs are given the responsibility to monitor the markets, and to punish those generators who exercise market power. PJM, in particular, is well-known for wielding a big market-monitoring stick and not being afraid to fine generators at the slightest hint of uncompetitive behavior [Lave, Apt and Blumsack 2004]. As the RTOs are responsible for maintaining balance between supply and demand in the grid, they may authorize the construction of new generation or transmission assets – though as we will discuss below, the RTOs have not been terribly aggressive on this front, in part because restructuring laws in the U.S. have not been clear regarding how the builders of new assets (transmission in particular) are to be paid for their investments.

Opening Retail Markets to Competition

The initial push to reform in the U.S. electric power sector came from consumers who saw power prices as being too high and blamed regulators and their local monopoly utilities. Since policymakers had come to believe that the generation portion of the industry could be made competitive in the form of liberalized wholesale markets, it followed naturally that retail markets could be opened up to competition as well. Consumers would, in theory, be able to choose from a number of different generating companies; they could choose based on price or other preferences (such as purchasing energy from carbon-free sources). The distribution network would remain the province of the utility and would be regulated, but the generation mix (on a regional or state level) would come to represent the preferences of consumers and not those of utilities or regulators.

Three issues have influenced retail competition policy in the U.S. The first was the belief that in a competitive environment, incumbent utilities would leverage their entrenched status and (in some cases) their generating assets to engage in predatory pricing or other anticompetitive behavior. Many states dealt with this situation by cutting, capping, and/or freezing utility rates, which pleased consumer advocates. The second issue was whether to enact retail competition for all customers or just a subset of customers. Some states were hesitant to enact retail competition for small residential customers since the potential savings would be small [Brown and Sedano 2003]. While some states (notably California and Pennsylvania) chose to open retail markets to all customers simultaneously, most others began by introducing competition for large customers and then slowly extending it to smaller customers. The final issue is the provision of default service in a competitive environment – that is, in the words of Brown and Sedano (2003), "serving customers who choose not to choose." Individual states are currently experimenting with a diverse set of policy options, although the two most popular appear to be naming the incumbent utility to be the default service provider and naming the default service provider using a competitive bidding process.

Highs and Lows

A broad-brush assessment of electric market reforms in the United States would paint California as an abject failure and laud the successes of the PJM market. Particularly from the point of view of policymakers, who like to see prices low and stable, there is much to support such an assessment. California's market required multiple interventions by state and federal officials before prices dropped; by then the "spikes" had lasted nearly one year and California taxpayers were $40 billion in debt. Imitation being the sincerest form of flattery, California is in the process of reshaping its wholesale markets to more-closely resemble those in PJM. FERC, meanwhile, has issued its preferred wholesale market platform which also appears to borrow heavily from PJM's operations [Lave, Apt and Blumsack 2004].

That California was an unmitigated disaster is surely beyond dispute, as is the proposition that prices in PJM have been lower and more stable. Market-design concerns aside, the comparison is both unfair and misleading. California's market suffered for so long in part because the Western U.S. is heavily dependent on hydroelectric generation, and the region in 2000 experienced its worst drought in over ten years [van Vactor and Pickel 2001]. Since price spikes in hydro-based systems are normally brought on by energy constraints in the form of low water levels, they tend to last longer than price spikes in thermal systems (such as PJM), which are often the result of unplanned generating outages that last only a short time. Imposing the market design of PJM on California will not solve the state's underlying supply problems any more than will price caps.

A more nuanced view of electricity restructuring in the United States would reflect high expectations and a sobering reality. Policymakers had looked to the unregulated merchant sector for investment; high prices (such as those in California) would surely provide incentives for the construction of new power plants and transmission lines. Investment in power plants has occurred, but mostly in the form of gas-fired facilities. The ensuing rise in natural gas prices has rendered many of these plants uncompetitive and has destroyed the financial position of the U.S. merchant generation sector. Competition in wholesale and retail markets has not yielded lower prices for consumers, as wholesale markets have proven to be less competitive than policymakers originally

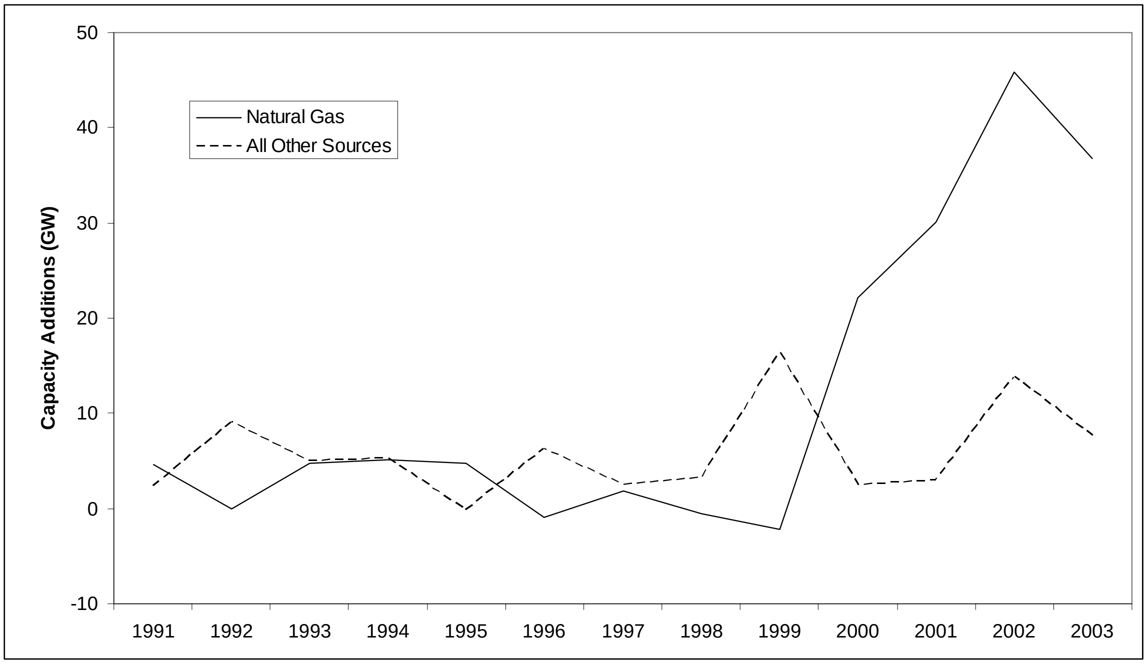

Figure 4: Generation Capacity Additions for Natural Gas and All Other Fuel Sources, in GW.
Source: *Energy Information Administration 2000; 2004.*

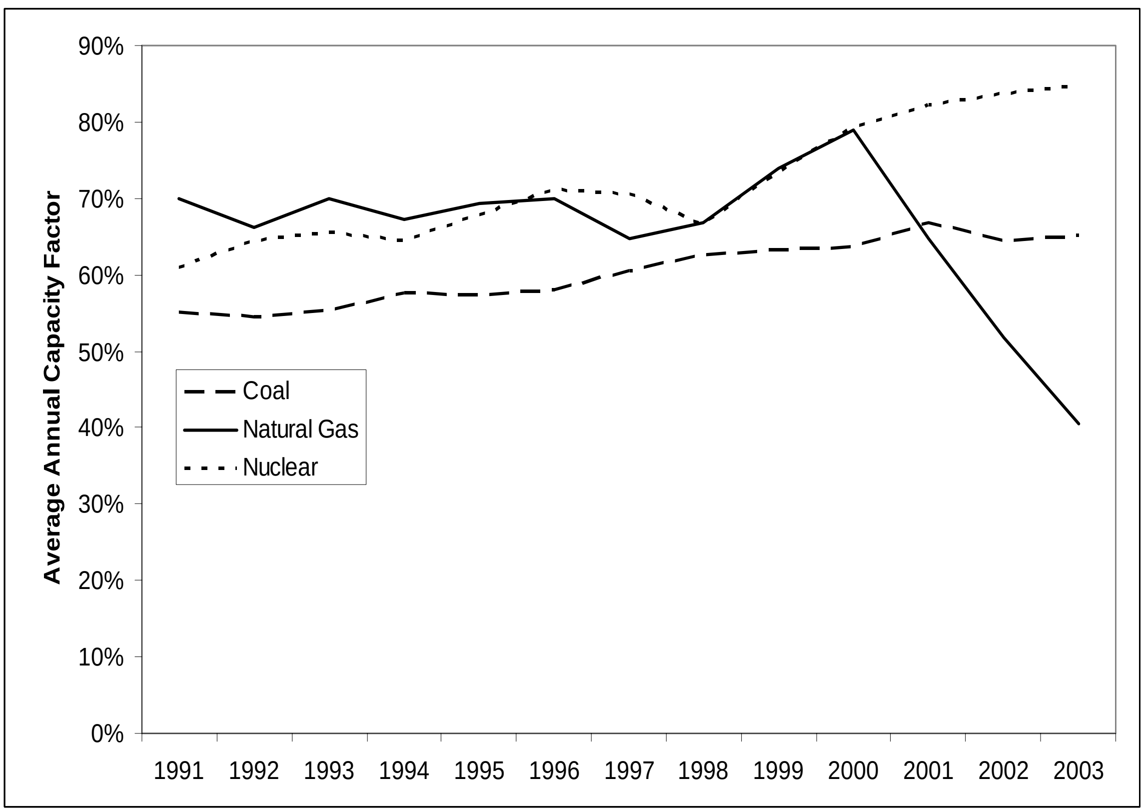

Figure 5: Average Annual Capacity Factors for Coal, Natural Gas, and Nuclear generation, 1991 – 2003. The capacity factor is calculated as the ratio of actual production (MWh) to potential production.
Source: *Energy Information Administration 2000;2004.*

believed, and the enthusiasm among U.S. consumers for "electricity shopping" has been minimal, with retail competition dormant or nonexistent in many states. Some large industrial customers have found that their formerly low-priced regulated rates have been bid up to market rates in restructured states, increasing prices sharply. Political deals struck to pass restructuring in some states have mandated that residential prices come down (and thus these prices in some states have fallen), but this is not the same as costs falling with competition.

The Gas Bubble and the Fate of Merchant Generation

In the late 1990s, after California and PJM had opened up their electricity markets to competition (with Texas and the remainder of the Northeast soon to follow), merchant generating companies found themselves in an enviable position. Electricity prices were starting to rise, yet fuel prices remained low. The result was a surge in power-plant investment, as shown in Figure 4. However, much of the new generation capacity has been gas-fired, and the recent rise in gas prices has rendered many of these units uncompetitive, particularly when compared to coal. While the utilization of other generation resources (measured by average capacity factors, as shown in Figure 5), has increased along with demand over the past several years, utilization of natural gas resources has plummeted. Much of the capacity built by the merchant sector is sitting idle.

Surely, Figure 4 represents economically inefficient investment; the pattern of natural-gas investment has mirrored other economic bubbles, such as the over-investment in data network fiber during the telecom bubble of the 1990s. Those assets have been sold off at bargain-basement prices and consumers are benefiting in the form of expanded broadband data offerings. In the end, it was investors and not consumers who suffered. Similarly, much of the natural-gas investment has come from merchant generators (also known as non-utility power producers) which did not exist before the start of electric-industry restructuring in 1992. As such, it has been investors in these firms, rather than the customers of utilities, who have borne the financial burden of hasty investments[13]. Consumers pay indirectly, as investors demand higher interest rates in the now-risky electric sector.

While the shifting of risk from customers to investors can be viewed in a positive light, the dark side is the "terrible" shape of the merchant generation sector [Joskow 2003]. The U.S. is a far cry from the days when bankers were so eager to lend money to Samuel Insull that they encouraged him to set up shell corporations to evade legal lending limits [McDonald 1962]. Now, due in large part to regulatory uncertainty and high fuel prices, U.S. investors are demanding much larger rates of return for merchant investments. As Krellenstein (2004), puts it, merchant generation and transmission is now viewed by the investment community as "project financing," meaning that the revenues from the investment are the sole source of capital-cost recovery. Interest rates for project-financed investment are typically quite high – 15% to 20% and even higher. Such projects can be more difficult to fund because they require issuing B-grade debt, which some institutional investors (such as mutual funds) are prohibited from holding. Investments made by traditional vertically-integrated utilities (or municipal or federal agencies) are viewed as "system financing," meaning that the recovery of capital costs could either occur through revenues from the investment or through some other source of cross-subsidization (such

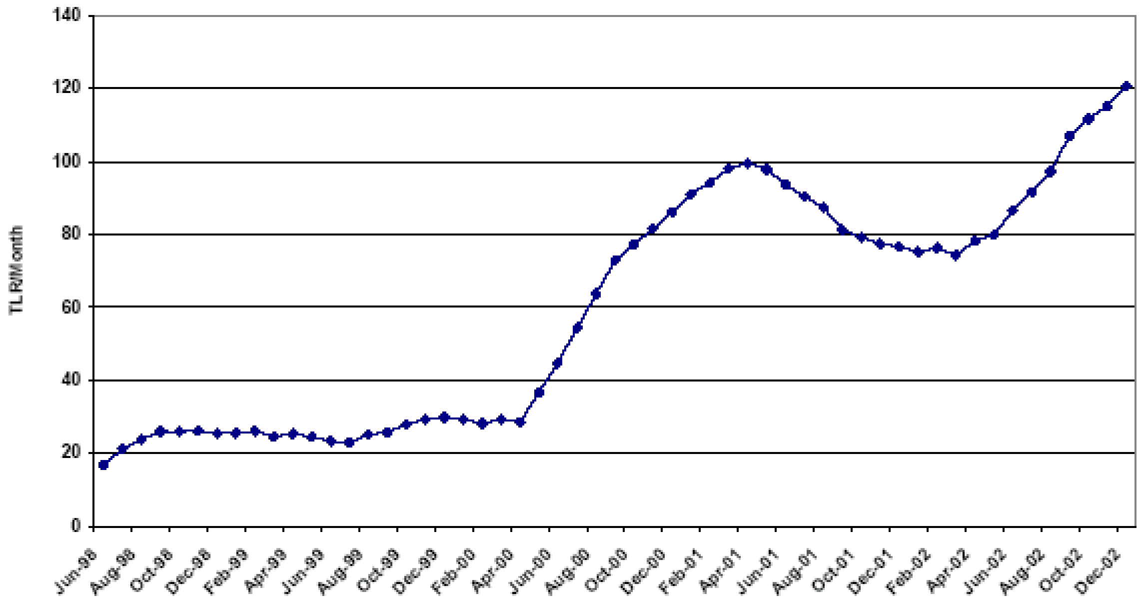

Figure 6: Transmission Loading Relief (TLR) Actions, June 1998 – December 2002.
Source: *Joskow 2003.*

Table 1: Share Prices and Credit Ratings in the U.S. Electricity Industry.

Company	May 2001 Peak Share Price	April 15, 2005 Share Price	April 15, 2005 Credit Rating
AES	48.50	16.50	B+
AEP	50.40	34.19	BBB
Calpine	54.70	2.39	B-
Duke	46.10	27.89	BBB
El Paso	64.90	18.91	B-
Mirant	45.40	0.31	N/A
Reliant	33.80	10.91	B+
Southern Cos.	23.54	31.95	A-
Williams	41.00	16.55	B+

Source: *Joskow 2003, Yahoo! Finance* (http://finance.yahoo.com, last accessed on 15 April 2005), *Standard and Poors* (http://www.standardandpoors.com, last accessed on 14 August 2005).

as revenue from customers, bond issuance, and so on). The financial community is willing to lend money to system-financed investments at much lower rates of around 10%.

Securities markets have not been kind to the merchant sector either, and have expressed their displeasure with the path of U.S. electricity restructuring by pricing the stock of vertically-integrated utilities at a premium to merchant-sector stock. Table 1, borrowed in part from Joskow (2003), shows the stock prices for several merchant generators and integrated utilities in 2001 (when power prices in California were still high) and 2005. Stock prices and credit ratings for merchant firms have slipped, while those for vertically-integrated and regulated utilities have been stable or have risen. Given the emphasis that U.S. electric restructuring has placed on the role of the merchant sector to drive competition and investment, the numbers from the financial sector look glum.

The Transmission Puzzle

Investment in transmission has been another problem entirely. In a competitive market, transmission must facilitate competition [Lave, Apt, and Blumsack 2004]; insufficient transmission will give certain generators locational market power. The increase in market transactions has stressed the power system noticeably; Figure 6 shows transmission loading relief (TLR) actions taken by vertically-integrated utilities over time. Restructured electric systems have had much the same experience, with congestion costs in PJM rising from $53 million in 1999 to nearly $500 million in 2003 [PJM 2005]. As in the case of generation, prices must send longer-term signals to the market in the absence of planning. The architects of electricity industry reform originally hoped that a merchant transmission sector would emerge in the same way a merchant generation sector emerged with the passage of the EPAct. Such a sector has not yet emerged, and as Joskow and Tirole (2005) note, the incentives of merchant transmission companies may be incompatible with those of the RTO. Further, it is possible to build new transmission lines in such a way as to cause congestion in other parts of the system; merchant transmission companies would undoubtedly have incentives to construct such lines and elicit payments from other market participants in exchange for not energizing those lines [Blumsack 2005].

Apt and Lave (2003) argue that pricing of congestion gives the proper signals to users to transmit power at uncongested times, but provides disincentives to investors. If the only payment is through congestion charges, no transmission owner would decrease his income by building a new line to relieve congestion. Prospective new builders would be discouraged, since the payments would decrease enough to put both the new and old owners out of business. The solution Apt and Lave propose is a 2-part tariff: congestion charges would remain (at a lower level) to discourage congestion, and the bulk of payments would be through an energy charge which would provide incentives for new construction and efficient operation.

The U.S. experience has shown that in the restructured electricity environment, investments in needed transmission will only occur with the aid of political will. Hirst (2001) notes that investment in U.S. transmission has fallen at an average rate of $117 million per year in the past thirty years. In the meantime, investment in generation has grown (see Figure 4). Transmission projects with clear social benefits have taken years to complete or gain approval, such as the Path 15 expansion linking Northern and Southern California [Hobbs et. al. 2004] or the Cross-Sound transmission line linking Southeastern Connecticut with Long Island [Krellenstein 2004]. Perhaps learning from the experience of New York, which could not get financing for a socially-beneficial transmission line linking Northern New York with New York City, the governors of four Western states have recently put their political muscle behind the construction of a high-voltage line linking coal-fired generation in Montana and Wyoming with demand centers in California.

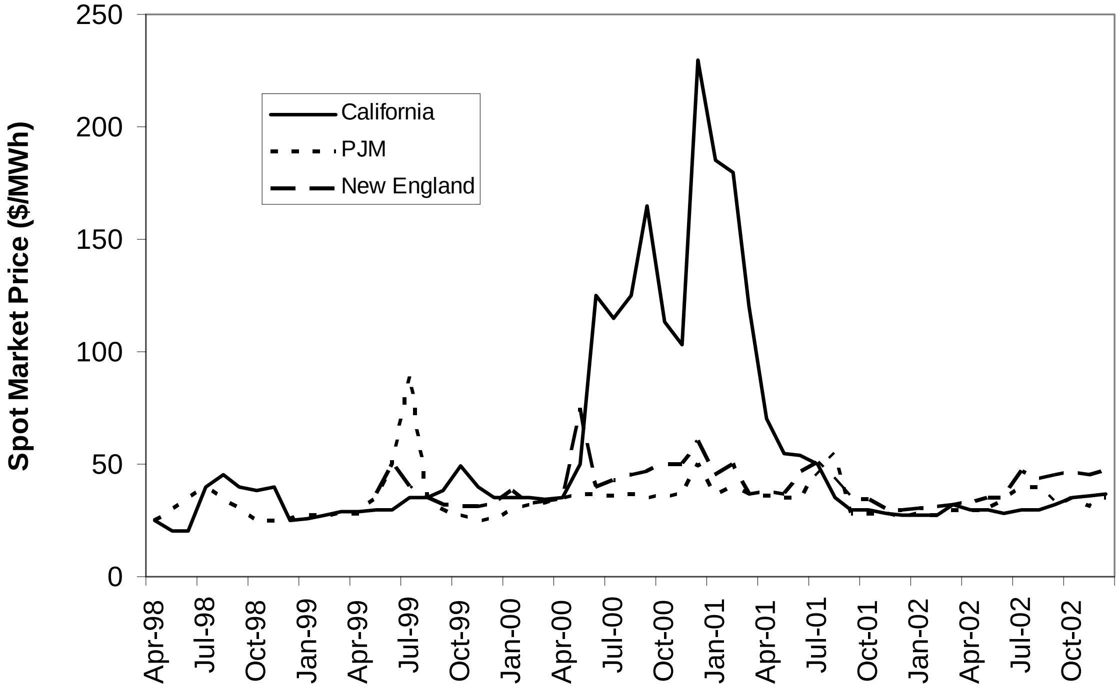

Figure 7: Spot Market Prices in California, New England, and PJM.
Source: *Bushnell, Mansur, and Saravia 2005.*

Wholesale Markets: Are the Prices and Incentives Right?

Electricity sector reform has created centralized spot markets for electricity in most of the Northeast as well as California. Bilateral markets exist in many of these areas (and others) but activity in these markets is poorly documented aside from a few survey-based trade publications such as Platt's *Megawatt Daily* and the independent *Energy Market Report*. Bilateral markets for bulk power serve various purposes; the most common appears to be trade in long-term contracts which currently cannot be done through any established RTO[14]. There is no record of the size of the bilateral market relative to the centralized spot markets run by RTOs, although the ISO New England reports that 75% of trading in its territory occurs on a bilateral level [ISO-NE 2003].

Figure 7 shows how prices for California, New England, and PJM progressed over the first few years of RTO spot markets. California's episodes of high prices are clearly visible. A great deal of ink has been spilt as to whether these markets are competitive; in fact, each RTO produces multiple reports on the subject each year. Virtually all after-the-fact analyses of California's market performance have concluded that the California market did not behave competitively during the summer of 2000[15]. The most well-known are those of Joskow and Kahn (2002), which examined generator withholding in California's markets, and Borenstein, Bushnell, and Wolak (2002), which examined bidding behavior. Somewhat less-academic evidence has come in the form of detailed revelations regarding the manipulative bidding strategies of Enron and other companies

[FERC 2003]. The other RTO spot markets have not been without their own episodes of uncompetitive behavior, though most have occurred soon after operations began[16]. Still, the general consensus, nicely summarized by Joskow (2003) is that under many supply/demand scenarios, the spot markets run by RTOs in the Northeastern U.S. have far outperformed those in California, at least in terms of extended price spikes.

Northeastern RTO spot markets may have behaved more competitively than California's spot market, but this does not necessarily mean that the structure of the Northeastern RTOs is competitive. Since electricity cannot be stored, whether a given power market is competitive boils down to more than just market shares. Based on market shares, every RTO spot market would rank among the most competitive markets in the U.S. in any industry[17]. Unlike other industries, the reality of electricity markets is that if supplies are tight enough, some firms can exercise nearly unlimited market power regardless of size; such firms are called pivotal suppliers[18].

FERC and individual RTOs have recognized the pivotal-supplier problem and are currently have triggers that alert market monitors as to when individual firms are in a pivotal position [Blumsack and Lave 2004]. In other work, [Blumsack, Perekhodtsev and Lave 2002], we have generalized the notion of a pivotal supplier to multiple suppliers acting in concert to withhold supply and raise price. We show that for many hours, 2 to 6 firms acting in concert could cause a blackout in California, PJM, or New York unless the ISO were willing to pay their price. Since generators who participate in RTO spot markets do so every hour of every day, it becomes very easy for each generator to figure out the others' bidding strategies and to collude implicitly. No secret meetings in smoke-filled rooms are required. Sarosh Talukdar (2002) has created a computer simulation with 10 firms, each having 10% of total system capacity. These firms are not as smart as human traders and learn slowly. Yet, even when capacity is twice the amount of electricity needed, the suppliers manage to raise the price to monopoly levels. Stephen Rassenti, Vernon Smith, and Bart Wilson (2003) reach almost identical conclusions in an experimental setting.

Eliminating regulation creates a free market. Creating a competitive market is more difficult; it requires that no seller have the power to increase profit by raising price. There is thus something of a dichotomy between market prices and market competitiveness, at least for the three Northeastern RTOs in New York, New England, and PJM. These markets nicely illustrate the difference between free and competitive markets. California's market was, relatively speaking, quite free. Generators were under no obligation to bid into the PX or ISO markets and could shop around for the best price. Markets in the Northeastern ISOs, however, are competitive by administration and are far from free. Generators in these markets have an obligation to bid uncommitted energy (that which has not been sold under contract or in the bilateral market) into the RTO spot market. Deviations from marginal-cost pricing are met with swift mitigation measures (including large fines), as market monitors are judge, jury, and executioner all rolled into one. PJM's market monitoring reports indicate that price caps are placed on all units dispatched out of merit order [PJM 2005]. Such un-economic dispatch can happen for a number of reasons aside from the exercise of market power, but PJM is apparently taking no chances.

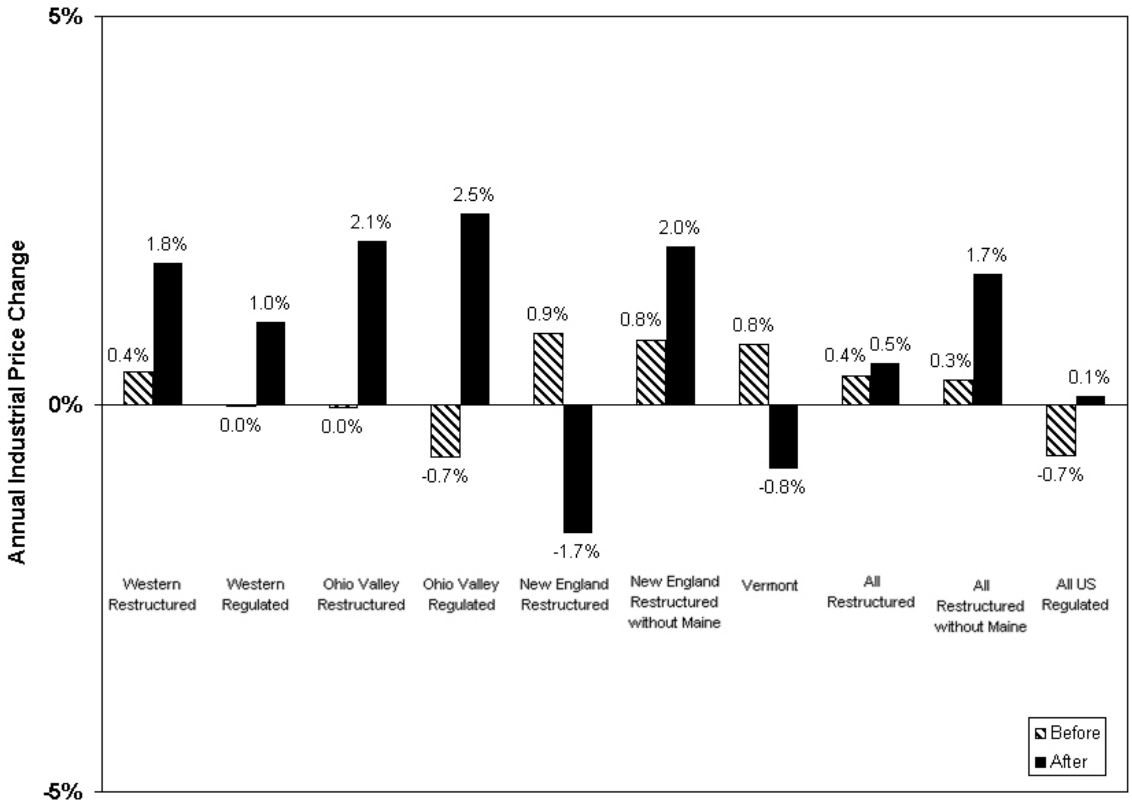

Figure 8: Industrial Retail Price Changes For Restructured and Non-restructured Regions.
Source: *Apt 2005.*

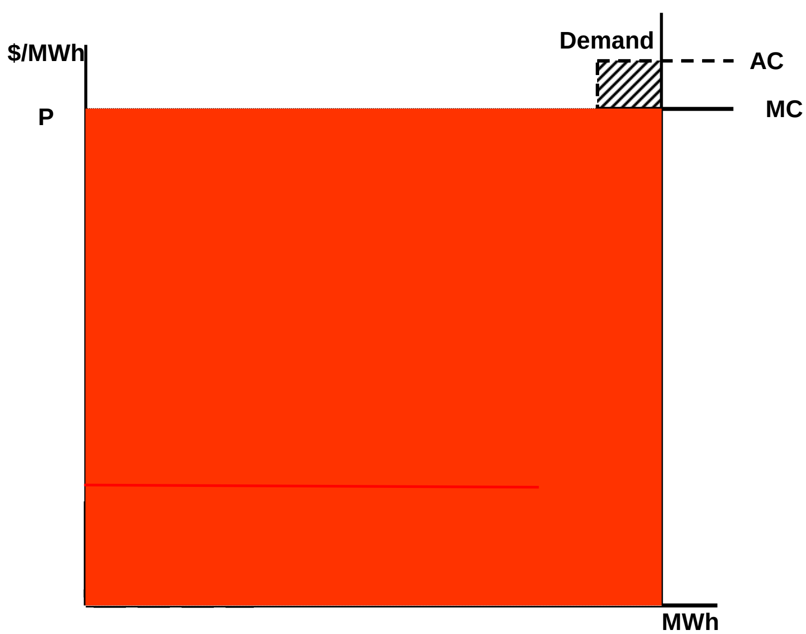

Figure 9: Centralized Auctions for Electricity May Raise Costs.
Source: *Lave, Apt, and Blumsack 2004.*

Spot prices may be fair for the purpose of keeping consumer prices from rising or utilities from going bankrupt (as happened in California when spot prices rose to many times the regulated retail price during 2000 – 2001). In markets, however, prices need to act as signals for investment. Figures 4 and 5 showed that low fuel prices for natural gas and high power prices in California led to a glut of gas-fired generating capacity. After California's crisis died down, the enthusiasm for investment in generation waned, particularly in the Northeastern RTOs which have not had sustained periods of high prices to spur investment. Of course, low prices indicate sufficient supply, at least for the time being. But if the only prices available are short-term in nature, then investors responding to those signals will create boom-bust investment cycles similar to those seen in natural-gas plants and in high-bandwidth fiber networks during the dot-com bubble. To complicate matters further, if those short-term prices are forced by the RTO to remain at politically palatable levels (as in PJM), then necessary investments will not occur and shortages will eventually rear their heads one way or another[19].

Wholesale and Retail Markets: The Missing Link

One frequent criticism of California's market design was that retail prices remained fixed while wholesale prices were allowed to fluctuate with the whims of the market [Sweeney 2002]. The result was the bankruptcy of California's two largest utilities, as well as rolling blackouts when the California ISO was faced with shortages. There are compelling economic reasons to believe that consumers would benefit from an arrangement whereby they could adjust their electricity usage in response to market prices, much in the same way they can alter driving habits or heating demand [Blumsack and Lave 2004; Borenstein 2005].

At least in the residential sector, there has been little political appetite for exposing consumers to wholesale electric market prices. Consumers in San Diego were charged market prices once the utility had finished paying off its stranded costs; unfortunately this coincided with the power crisis in the summer of 2000. Customers' bills skyrocketed and politicians forced San Deigo Gas and Electric to reinstate the old regulated rates [Bushnell and Mansur 2005]. Much of Massachusetts is about to embark on a bold experiment in real-time pricing, with its default retail prices no longer regulated and few if any alternative suppliers willing to serve the Massachusetts market.

Competition in wholesale markets was supposed to benefit consumers. Whether this has happened is far from clear. CAEM (2003) reports tremendous savings in PJM for all customer classes as a result of wholesale and retail competition. Joskow (2003) notes that retail prices in most restructured states have fallen. Based on this evidence, it is easy to conclude that electric sector reforms have been successful, at least in this one respect.

The reality of the situation is not so easy and serves to illustrate the difference in prices and costs, as pointed out by Lave, Apt, and Blumsack (2004). Prices have fallen in large part because regulators have demanded that they do so. The roughly 1% decrease in Pennsylvania's retail prices reported by Joskow (2003) matches the regulators' mandates. For much of the retail sector, regulators have maintained a divide between activity in the wholesale markets and demand by the end-use consumer. The one exception appears to be large industrial customers, who have the resources and best incentives to search for the lowest electric prices. If competition is to lower prices for any sector, the industrial sector would appear to be the best bet.

The bet, however, is a losing one. Apt (2005) has examined industrial electricity rates for each state since 1990. He finds no evidence that prices for industrial customers have gone down since restructuring; in many cases they have actually increased more than prices in states which remained regulated. Figure 8 summarizes the data by region. Industrial prices in restructured states have increased by, on average, 1.7%, while prices in regulated states have barely budged. The case of Maine is separated from the rest of the data in Figure 8 since price decreases in Maine were due largely to an influx of new natural-gas supplies (Maine depends heavily on natural gas but has few native resources) and had little to do with electric-market competition.

Retail Competition

America's legendary enthusiasm for shopping does not appear to have transferred to selecting electricity providers. With a few exceptions, residential switching activity in the competitive retail market has been minimal at best. Even if residential consumers wanted to switch, many service areas, notably in Massachusetts and New Jersey, simply don't have any competitors to the incumbent utility. Table 2 shows the total load served by competitive (non-utility) electric service providers (ESPs). Seventeen states currently offer some form of retail competition to at least some of its consumers; the states shown in Table 2 are meant to be representative. Residential activity in competitive retail markets has been low, with the exception of some traditionally high-cost urban areas[20]. Commercial and large industrial customers have switched providers in much higher numbers.

In one sense low levels of switching activity in the residential sector is not surprising. While Rose (2004) calculates that residential consumers have saved approximately 0.9 billion dollars since the inception of state retail competition programs (often due to mandated rate reductions, which are soon to expire), total residential expenditures in 2003 amounted to over 110 billion dollars [EIA 2004]. Cumulative savings by residential consumers over several years has thus amounted to less than one percent of annual expenditures. In pure dollar amounts, the savings to individual residential customers is small, and may not be sufficient to overcome whatever search costs and switching costs consumers must bear. The result, noted by Joskow (2003) and Rose (2004) is that competitive ESPs have been leaving the market in large numbers.

Where From Here? Reform of Reforms[21]

After having been burned by California and the eventual realization that the most successful electricity market designs are also the most highly managed and regulated, the U.S. electric power industry and its regulators are at somewhat of a crossroads. Two central questions remain. The first is the extent to which the electricity industry can truly be deregulated, as opposed to a restructuring which trades one set of high-cost regulating institutions (state public utility commissions) for another (RTOs and an increased federal presence in the industry). The second is the speed and breadth of reforms.

Table 2: Percent of energy(MWh) served by competitive electric service providers (ESPs) for selected states, as of December 2004.

	Pennsylvania	Massachusetts	Ohio	New York
Residential	7.1%	3.2%	15.4%	6.9%
Commercial	29.3%	14.7%	36.1%	36.5%
Industrial	14.3%	53.3%	10.7%	66.9%

Source: *Pennsylvania Office of Consumer Advocates (*http://oca.state.pa.us, last accessed on 14 August 2005), *Massachusetts Department of Public Service (*http://www.mass.gov/dpu, last accessed on 14 August 2005)*, Ohio Public Utilities Commission (*http://www.puc.state.ohio.us, last accessed on 14 August 2005)*, New York Department of Public Service (*http://www.dps.state.ny.us, last accessed on 14 August 2005).

The industry has unfortunately been so caught up with the second question that it has not properly dealt with the first question. The message from industry analysts has been resoundingly clear: Go Slow. This is certainly prudent advice; natural-gas and petroleum deregulation has been viewed as so successful that it is easy to forget that the process took several decades worth of experimentation and effort. However, the issues facing electricity are very different than those facing oil or natural gas; as a result the institutions created in oil and gas restructuring (in particular, the development of liquid futures markets) are unlikely to have the same effect in the electric sector. We thus conclude with a list of issues meant to address the first question: how far can you push electricity deregulation? Our hope is that policymakers in the U.S. and other countries will seriously consider these issues before proceeding down what could be an inappropriate path.

Electricity Markets May Inherently Raise Costs

Most RTO spot markets are centralized auctions in which all market participants are paid the price of the marginal unit (such an auction is called a uniform price auction). This is illustrated in Figure 9. The solid line in the figure is the marginal cost of generation, while the dashed line is the average total cost, including fixed costs. The vertical line is the number of MWh demand during a particular period, as estimated by the ISO. In a competitive market, all generators would bid their marginal cost for each unit and the market clearing price would be P. Since the market-clearing price is paid to all generators in a uniform price auction, the total amount paid to generators would be P times the number of MWh, a rectangle that is the shaded area. Under regulation, generators are paid their average (unit) costs and so the total amount paid is the cross-hatched area. At times of high demand, such as shown in the figure, the amount paid under a uniform price auction is much greater than under an average cost system[22].

Deregulation requires new institutions, primarily to perform functions formerly carried out by vertically integrated utilities. Creating an effective new institution is expensive and time consuming. Start-up costs for the California ISO have been estimated as high as $1 billion and its budget is nearly $200 million per year; the budget for PJM is nearly $250 million per year [Lutzenheiser 2004; van Vactor 2004]. The ISOs cover their operating costs through fees imposed on system participants and congestion payments. Aside from the costs involved with formal institutions, market-based deregulation imposes costs on individual participants in the form of maintaining trading desks and gathering market information. Enron's operating expenditures in 2000 to take part in the various energy markets (gas, oil, and electricity) were quoted at $449 million[23]. In a restructured market, firms must either assume these costs or exit the market. Therefore, the social and private costs of setting up new market institutions must be accounted for in determining whether restructuring yields a net social benefit.

Creating Competitive Markets

Electricity market structures in the U.S. are less than competitive [Blumsack, Perekhodtsev and Lave 2002]; market performance in PJM and other Northeastern RTOs has been reasonably competitive due to tight controls on bidding behavior, not by inherently competitive markets. At least in the U.S., creating competitive markets through additional investments or divestiture in order to mitigate the pricing power of pivotal suppliers would raise costs; the effects on the margin would be substantial [Blumsack and Lave 2004].

A further complication arises in that not only must energy markets have competitive structures, but markets for all types of energy (short- and long-term) and ancillary services must be complete and competitive. If not, generators with market power in one of the markets can leverage it to earn higher prices in other markets. California's market design gave some generators incentives to withhold energy from the PX or ISO auctions, moving instead to more lucrative (and less competitive) ancillary-services markets. California's move to long-term contracting provides a slightly different example. Following the power crisis, California announced that it would begin purchasing much of its energy on a long-term basis and set out to negotiate prices with generators. The contract prices that California was able to get were often $100 per MWh or even higher, as generators realized California's desperation and were able to take advantage.

Increased Risk in a Capital-Intensive Industry

One side effect of regulation was that it helped to lower the risk associated with utility industries. Each year, demand would rise at a reasonably predictable rate, technology would improve, and real prices would fall. The lack of competition and the fact that rates of return were virtually guaranteed by regulation was a boon to utility stocks and bonds. Investors, seeing utilities as low-risk companies, were willing, ready, and eager to lend money to the electric power industry at very favorable rates.

Under rate-of-return regulation, the risks were borne by ratepayers. Under deregulation with fixed retail prices, the risks have largely shifted to investors[24]. The uncertainty cannot be wished away. Placing the risks on ratepayers lowered borrowing costs but caused retail prices to rise when utility companies made bad investments. Intervention by regulators in California's power crisis, uncertainty over the future course of regulation/deregulation, and the glut of natural gas generation has changed the way investors view the electricity industry and has needlessly increased the cost of capital. Investors have begun to demand higher rates of return, particularly from the merchant sector, and some investors are unwilling or unable to lend money at any rate. For the electric power industry, in which capital represents around two-thirds of the cost of generation equipment and nearly all of the cost of transmission lines, the result is that the total cost of new infrastructure has risen significantly.

Transmission Must Facilitate Competition

The transmission grid serves the same purpose as a pipeline network for natural gas: it can connect low-priced supplies to high-price markets, as it does in much of the eastern U.S., or it can act as a vehicle for the exercise of market power, as it appears to have done in California. As shown in Figure 6, the transmission system in the U.S., which was built to accommodate the needs of a vertically-integrated utility serving its own load with its own generation, does appear to be under stress. Current market signals for transmission are short-term in nature and indicate the need for short-term solutions (dispatch) rather than investment.

Conclusion

The U.S. electricity industry is currently in something of a hybrid state. Two-thirds of the states have retained their regulated utility structure, while a handful have moved towards deregulation and spot markets. Some are stuck in the middle with attempts at competition in the retail sector and regulation at the utility level. In all cases, it has become clear that the existence of a “market” for electricity (in the same way that there are markets for natural gas, petroleum products, or even pizza) is a myth; market micromanagement by RTOs and federal regulators has replaced regulators and rate cases at the state level. The industry has simply traded one form of costly oversight for another, and has traded imperfect regulation for imperfect markets.

At this point, the two-thirds of states choosing to remain regulated with vertically-integrated utilities are holding their ground and refusing to restructure, despite FERC’s insistence that they do so. These states are concentrated in the Southeast and the Northwest, where power costs have traditionally been among the lowest in the U.S., and the Great Plains, which is dominated by rural and agricultural areas. Given the additional costs that restructuring imposes, the insistence of these states that they should be allowed to retain their traditional industry structure is not surprising, and suggests that the current hybrid state of the U.S. power industry will remain for some time.

Reform of the U.S. electricity sector has been a messy and chaotic process. Moreover, the process has been highly politicized and in some cases grossly ignorant of the physical realities of operating an electric power grid. California’s restructuring law was written by a swarm of lawyers, economists, and interest groups, without any input from power engineers. FERC’s Standard Market Design tried to foist hourly spot markets on regions like the hydro-rich Pacific Northwest, where long-term signals are required to efficiently manage hydroelectric resources. What has ultimately stymied meaningful electricity reform is the ideological path it has taken. Markets should be a means to an end; in the case of electricity, the market itself has been the end. If reforms are to be pushed further along, policymakers need to think much more carefully about what *policy* goals they hope to attain (and how they might measure whether the goals have been achieved), not only about the institutions best-suited to those goals.

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[2] The most striking proponent is the libertarian Cato Institute, which has advocated that restructured states return to a market structure of vertically-integrated and regulated electric utilities. See Taylor and van Doren (2004).

[3] Investments in nuclear generation proved particularly problematic, as utilities learned that it was much more difficult to build and operate nuclear plants than fossil-fuel plants. Nuclear-related debt from the Washington Public Power Supply System (WPPSS) resulted in the State of Washington defaulting on $2.5 billion worth of interest payments in 1983. At the time it was the largest municipal default in history [Bennet and DiLorenzo 1983].

[4] The primary purpose of PURPA was, in fact, to reduce the U.S. reliance on imported crude oil, which accounted for nearly 20% of electricity generation at the time.

[5] Bilateral trading had been underway in the West for a number of years prior to EPAct. In 1987, the Federal Energy Regulatory Commission (FERC) approved the Western Systems Power Pool (WSPP), which allowed utilities in the Western Interconnect to trade surplus electric power at market-based rates. Its success paved the way for the EPAct [van Vactor 2004].

[6] This does not mean that FERC has backed away from industry restructuring. As per Order 2000, the Commission still insists that all utility operating areas form or join an RTO.

[7] California's ISO is currently trying to gain FERC approval. Since Texas' electric grid has no interconnections with neighboring areas, FERC has no jurisdiction over the state's ISO.

[8] PJM was actually the first such power pool in the U.S., dating back to the 1920s.

[9] Joskow (2003) argues that California's market design also represented a break from reality. While the initial debates over market structure were reasonably open and inclusive, the final restructuring bill (known as Assembly Bill 1890) was written entirely by lawyers, lobbyists, and economists; power system engineers were excluded from the process.

[10] The law was actually a bit more subtle. California allowed the IOUs to retire their stranded-cost debt over a period of four years using a formula based upon the difference in the regulated retail price and the price of energy in the state's centralized spot market. The IOUs could engage in bilateral contracting, but the excess revenue from those purchases could not go towards retiring stranded costs, and any remaining stranded costs at the end of four years would remain on the IOUs' books as debt. The IOUs had such massive stranded costs that their clear incentive was to stick with the centralized spot market.

[11] Zonal or nodal pricing may alter behavior to promote system security if the prices represent congestion differentials. However, as shown by Bohn, et. al. (1984) and Wu, et. al. (1996), price differentials in electric grids may arise for a number of reasons other than congestion. Further, even if price differences do arise because of congestion, it is not necessarily true that the line sporting the price differential is congested.

[12] Automatic Voltage Control (AVC) is used in parts of Europe.

[13] Though to be fair, if the industry had not undergone restructuring, it is unlikely that regulators would have approved natural-gas investments on the scale of what was seen in the merchant generating sector.

[14] The now-defunct California Power Exchange (PX) flirted briefly with forward markets around the time of California's energy crisis.

[15] The most compelling argument that California's power crisis was not primarily the result of market manipulation by power traders can be found in van Vactor and Pickel (2001). The debate over what exactly went wrong in California has been spirited at times. During the power crisis, California politicians, particularly then-governor Gray Davis, pointedly accused merchant generators and marketers of manipulating the state's energy markets to raise prices and profits; the result was mockery by those outside California and something of a rebuke from Curtis Hebert, then the chair of the FERC.

[16] See Mansur (2001) (PJM), Bushnell and Saravia (2002) (New England) and Bushnell, Mansur, and Saravia (2004) (a comparison of California, PJM and New England which finds evidence of anticompetitive behavior in all three markets).

[17] The standard metric for market concentration in the U.S. is the Herfindahl-Hirschman Index (HHI). The HHI measures the sum of the squared market share of each firm; it ranges from 0 (perfect competition) to 10,000 (monopoly). U.S. antitrust regulations define a concentrated (or uncompetitive) market as one with an HHI of 1,800 or higher. The HHIs in California, PJM, and New York are 664; 1,160; and 637, all of which indicate a competitive market [Blumsack, Perekhodtsev and Lave 2002].

[18] The reason is that supply/demand imbalances can result in blackouts. If the generation capacity of a given company is needed to prevent blackouts, then that company can charge a high price even if it has a small market share.

[19] In order to provide incentives for investment, RTOs have started "capacity" auctions, which make payments to generators simply for being available and ready to produce power. As these auctions are reasonably new, it is hard to tell whether they will have the desired effect. NYMEX has offered electricity futures contracts since 1996, but they have fared poorly; of the six electricity contracts offered by NYMEX, only the PJM contract is still traded.

[20] The biggest success in retail competition at the residential level would appear to be Ohio, where more than 60% of residential customers in the Cleveland area have switched electricity providers. However, as Brown and Sedano (2003) note, many customers in Ohio have received subsidized rates in exchange for switching.

[21] This section borrows heavily from Lave, Apt, and Blumsack (2004).

[22] An alternative to the uniform price auction would be a discriminatory-auction, in which all participants are paid their bids instead of the price of the marginal unit. Federico and Rahman (2003) have shown that the two auction structures are likely to produce similar results as generators learn the bidding strategies of other participants.

[23] Enron's financial reports are still available at http://www.enron.com. Although the cooking of Enron's books is now widely acknowledged (and the exact figures therefore suspect), the point is still that the cost to participate competitively in restructured electricity markets is too high for many small players.

[24] California shifted some of that risk back to ratepayers when retail rates were raised in the midst of the power crisis.