The electricity system at the crossroads—Policy choices and pitfalls

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Introduction and summary

In the mid-1980s, electricity policy in the United States began a new chapter when wholesale electricity markets were opened to competition. While the immediate goal was to increase the diversity of supply for electricity generation, proponents of restructuring also cited other dimensions of success arising from the restructuring of other network industries (such as telecommunications, airlines, and natural gas) as justification for introducing competition to the electric utility industry. Wholesale competition for producing electricity would improve generation efficiency, diversify supply, promote innovation, and even lower prices. Success in opening the wholesale market, proponents argued, would eventually be extended to the retail market, and all consumers would have the opportunity to choose their supplier and pick an electricity service that best fit their individual needs.

The initial enthusiasm for restructuring was particularly noticeable in states with high electricity prices. In theory, splitting the traditionally integrated functions of a utility—power generation, transmission, and distribution—into separate functions would expose cross-subsidies and inefficiencies, and competition among power generators would lead to lower prices for all classes of customers. Restructuring was designed to introduce open market competition only in electricity generation. Transmission and distribution services would still be subject to varying levels of regulation. By 2000, almost half of the states were pursuing some form of restructuring. However, several recent events have cooled the enthusiasm for abandoning the traditional heavily regulated and integrated utility system. Foremost among these was the California electricity crisis. The state garnered daily headlines as a series of events, including a flawed restructuring plan, left California facing skyrocketing prices, potential blackouts, and bankrupt utilities.

California's high-profile bad experience clearly demonstrated that the costs of a flawed electricity restructuring policy could be very high. In addition, states that had demonstrated early success in restructuring, such as Pennsylvania, Connecticut, and Massachusetts, were beginning to find that sustaining competition and promoting new market entrants was harder than they had anticipated.

This apparent conflict between theory and outcome has left restructuring at a crossroads. States are examining what elements and structures need to be in place to realize the promise and benefits of opening electricity markets to competition. The questions policymakers need to answer include the following:

- Is the physical infrastructure (particularly, adequate supplies of generation and transmission) in place to support new market entrants and a competitive market?
- Are the incentives for investing in new electricity facilities adequate? What can be done to improve these incentives if they are lacking?
- Do new institutions need to be developed to facilitate this new structure for delivering electricity? Should these be federal, regional, state, or quasi-public institutions? What is the role for existing regulatory institutions?
- Should restructuring expose consumers to changes in electricity prices, even when those prices can be volatile?

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- What is the relationship between meeting environmental goals and generating greater power supply? Can the two successfully coexist?

In this article, I examine what restructuring means in the electricity field. I discuss the legacy of the existing electricity system, which favored local electricity provision by integrated and highly regulated monopoly utilities, and describe the issues involved in moving to a more market-based system. Then, I use the five states of the Seventh Federal Reserve District as a case study for examining how restructuring issues are being addressed at the state level. The states of the Seventh District provide a particularly useful example, given that restructuring programs in Illinois and Michigan are well underway with consumers to be provided with retail choice in 2002. In contrast, Indiana, Iowa, and Wisconsin have adopted a cautious approach to restructuring, as relatively low prices for electricity have led them to question the immediate benefits of abandoning their existing structure for delivering electricity. Based on this analysis, I identify some lessons that can be applied as electricity policy continues to evolve. Evidence suggests that defining the role of existing and new institutions in managing the transition to market competition is one of the keys to promoting electricity restructuring. This may include insulating these institutions from political interference. Similarly, we need to examine how markets are structured to provide access to competitive electricity supply sources, as well as recognizing how the unique attributes of electricity create challenges for trading power as a commodity. Finally, policymakers need to consider the role of the electricity consumer in restructuring. For restructuring to succeed, consumers need to be exposed and to respond to legitimate market-based changes in electricity prices. Price signals that reflect fundamental changes in the cost of generation need to be passed through to consumers. While consumers may be provided with tools to manage volatile electricity prices, creating barriers to prevent price changes from being reflected in utility bills will not provide incentives for consumers to conserve electricity or for firms to invest in expanded generation.

Understanding the legacy of the U.S. electricity system

For much of its history, the electric utility business has received little public attention. Electric policy assumed that utilities were natural monopoly providers of a regulated and essential public service. Consumers were told which company would be their electric provider and how much they would pay for the service based on the service territory they were located in. Decisions regarding 1) how energy was generated, 2) if new plants were necessary, and 3) how much should be charged were largely discussed inside utility companies and in hearing rooms at state public utility commissions.

There were good reasons for maintaining this structure. The electric utility business is a very capital-intensive industry. Investments in power plants, transmission, and distribution systems are expensive and long-lived, and it would be inefficient to build overlapping systems within the same service territories. The clear public policy response was to recognize the monopoly status of utility companies, provide the companies with defined geographic service territories, and then subject them to rigorous regulation so as to prevent the exercise of pricing power.[1] The same rationale was applied to other "network" industries, such as telecommunications, where the policy goal of providing service to everyone (universal service) at a moderate price was viewed as a primary objective. For the most part, this led to a regulatory compact in which utilities received monopoly status in return for a pricing structure based on tariffs that were "just and reasonable" (for example, that reflected the utilities' cost of production and delivery) and that provided for a fair rate of return on invested assets.

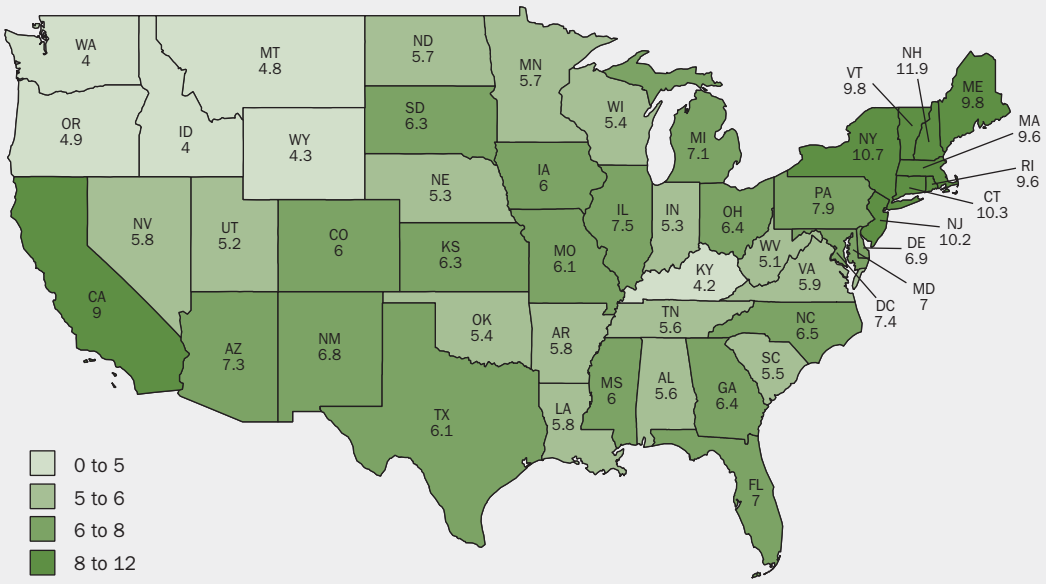
This emphasis on local monopoly provision and local policymaking led to a highly fragmented electricity system in the U.S. Everything from the price charged for electricity to the fuel used for generation varied widely from region to region. Figure 1 demonstrates the extreme variability in the "price" (as measured in average revenue per kilowatt hour [kWh]). For example, while the price of electricity is a mere 4 cents in Idaho, where hydroelectric generation keeps costs low, it is nearly triple that amount in nuclear dependent New Hampshire at almost 12 cents. In both states, the average revenue received by the state's utilities is justified based on a review by the state public utility commission of the cost borne by the utility to generate and deliver energy in its service territory.

The choice of fuel is a very significant factor in price variability. Figure 2 provides a historical perspective on the costs of coal, natural gas, and petroleum at the national level. Coal has exhibited very steady and slightly declining costs, while petroleum and natural gas costs have demonstrated significantly more volatility. In particular, the rapid run-up in natural gas costs from 2000 through the first part of 2001 posed major challenges to natural-gas-fired generators.

Electric prices also vary by class of customer served (see table 1). Industrial customers are often charged lower tariff rates because they are easier to

FIGURE 1

Average revenue from electricity sales to all retail customers by state, 1998 cents per kilowatt hour

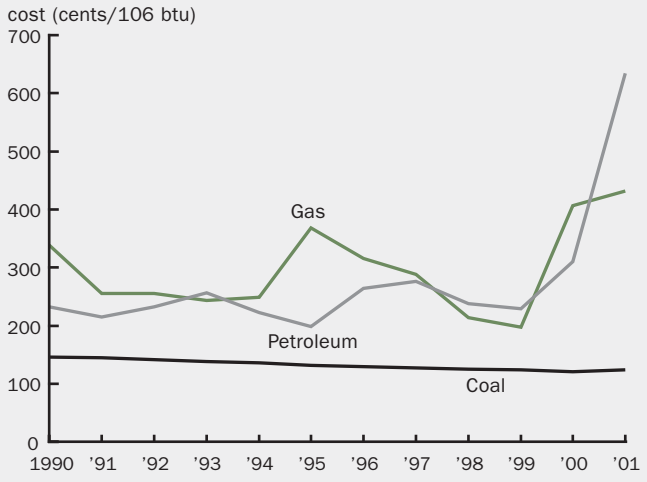


Source: U.S. Department of Energy, Energy Information Administration, 2000, "The restructuring of the electric power industry: A capsule of issues and events," report, January.

serve. As bulk users of electricity, they often draw a highly predictable and steady level of power and, as a result, their costs of service (for example, connections to the grid) are often lower than for residential customers. Providing residential service requires managing a more variable load and can only be accomplished through a large distribution system, supported by higher maintenance and billing costs.

FIGURE 2

U.S. electric utility average cost for fossil fuels, 1990 through May 2001



Note: btu is British thermal unit.
Source: U.S. Department of Energy, Energy Information Administration, 2001, "U.S. electric utility receipts of and average cost for fossil fuels, 1990 through May 2001," table, available on the Internet at www.eia.doe.gov/cneaf/electricity/epm/epmt26p1.html.

The system of governance of utilities is also fragmented. For the most part large, vertically integrated, investor-owned utilities are responsible for generating, transmitting, and distributing power to customers. However, other forms of utility ownership are also popular, including municipal ownership, cooperative ownership, and even federal power utilities such as the Tennessee Valley Authority and the Bonneville Power Authority (see table 2). These differences in governance have important ramifications for regulatory outcomes. While large investor-owned utilities (IOUs) are subject to review by state public utility commissions, many public power authorities are exempt from these requirements. This fragmented structure makes electricity a policy area with many participants and little central planning or review

TABLE 1

Electricity price by class of customer

	Value	Highest	Lowest
Average electricity price (cents/kWh)	6.66	NH(11.75)	ID(3.98)
Industrial	4.43	NH(9.21)	WA(2.70)
Commercial	7.26	NH(11.39)	ID(4.20)
Residential	8.16	NH(13.84)	WA(5.10)

Note: Prices are based on the contiguous U.S. NH is New Hampshire; WA is Washington; and ID is Idaho.
Source: U.S. Department of Energy, Energy Information Administration, 1999, "Average revenue per kilowatt hour by sector, census division, and state (cents)," available on the Internet at www.eia.doe.gov/cneaf/electricity/esr/t12.txt.

authority, except within the balkanized areas served and regulated by a public authority.

The start of a new era—Wholesale deregulation

In 1978, the passage of the Public Utility Regulatory Policies Act (PURPA) opened the wholesale power market to certain non-utility generating companies. PURPA was passed to help reduce U.S. dependence on foreign oil and to expand the diversity of supply for U.S. electricity generation. By 1998, non-utilities were responsible for 11 percent of the total generation in the nation and were contributing 406 billion kWh to the electric system. PURPA was followed by the passage of the Energy Policy Act of 1992 (EPACT). One aspect of EPACT was to further press wholesale deregulation by opening up transmission access to non-utilities. In return, regulated utilities were permitted to build new merchant plants outside their service territories.

Other landmarks in restructuring were regulatory Orders 888 and 889 issued by the Federal Energy Regulatory Commission (FERC). Both orders were issued in 1996 and were designed to pave the way for increased participation by non-utilities and promote wholesale competition by eliminating local utility monopoly control over transmission. The combined effect of these orders required public utilities that controlled transmission to develop open access, non-discriminatory transmission tariffs and to provide existing and potential users with equal access to transmission information. These orders also began the process of "unbundling" existing utility functions by separating transmission of electricity as a stand-alone service from generation and distribution.[2] The opening of access to transmission lines was a significant step. States with high-priced electricity hoped that the development of an active and open wholesale electric market would serve as a base for moving into retail deregulation. Increased wholesale competition would provide local distribution companies with more options over how to meet their load obligation, and eventually individual consumers would be able to choose their electricity generator.

By 1999, FERC pushed the issue of opening the transmission grid one step further with the adoption of Order 2000.[3] This order encouraged states to form Regional Transmission Organizations (RTOs) to improve the multi-state operations of the transmission grid. The RTO was to serve as a multi-state, independent organization to manage the operation of the transmission grid for particular regions. The order provides specific (but voluntary) guidance concerning a minimum set of eight functions that an RTO must be able to perform, but it leaves it up to the states and the utilities to develop both the geographic footprint and the governance structure of the RTO. The suggested eight minimum functions are: responsibility for tariff administration and design; congestion management; parallel path flow; ancillary services; total transmission

TABLE 2

Utility retail sales statistics, 1998

	Investor-owned	Public	Federal	Cooperative
Number of utilities	205	1,951	7	852
Number of retail customers	91,889,360	18,002,349	33,544	14,115,259
Retail sales (mWh)	$2,427,733,133	$485,692,301	$46,631,180	$279,761,845
Percentage of retail sales	74.9	15.0	1.4	8.6

Source: U.S. Department of Energy, Energy Information Administration 1999, *State Electricity Profiles*, available on the Internet at www.eia.doe.gov/cneaf/electricity/st_profiles/toc.html.

capability and available transmission capability; market monitoring; planning and expansion; and inter-regional coordination. In 2001, FERC clarified its goals by arguing for the formation of as few as four very large RTOs to cover the entire national grid.[4]

What does restructuring mean?

Electricity is provided to consumers through a very complex mechanism. This mechanism is complex from both a technological and regulatory perspective. On the technology side, providers must match energy supply and highly variable demand by managing different sources of generation that operate at differing levels of efficiency. This process includes taking into consideration scheduled and unscheduled generation shutdowns, changes in fuel prices, seasonal variation, a shifting customer base, and even daily weather. On the regulatory side, electricity policy is the shared responsibility of federal, state, and local policymakers. Jurisdictional boundaries between these various regulators are not often clearly drawn, and policy goals can come into conflict. Given this complexity, it is not surprising that there is no single definition for "electricity restructuring." However, in most cases, restructuring focuses on taking the once integrated functions of a traditional regulated utility—generation, transmission, and distribution—and separating or unbundling them into stand-alone services. In the case of generation, the goal of the unbundling is to introduce competition. In the case of transmission, the restructuring goal is to modernize the transmission infrastructure to support open access to the grid and the most efficient delivery of bulk electricity on both an intra- and inter-state basis. Efficient transmission allows the cheapest power to be used first and reduces the overall peak power or back-up capacity needed in the system. In the case of distribution, it is hoped that unbundling will make it easier to identify the true cost of distributing electricity, thereby eliminating hidden costs and cross-subsidies among end-users of electricity.

The starting point for the restructuring debate focuses on creating competition for generation through market deregulation. Vibrant supply competition is at the core of the restructuring argument. On the positive side, choice of generation supply can allow consumers to select more customized electricity service, while putting market pressure on generators to innovate and produce more efficient generation alternatives. Supplying competitive choices for generation would help better manage system peak load demands by providing more options to distribution systems when electricity shortages occur. However, if generation competition fails to develop, eliminating traditional regulatory safeguards can result in consumers being exposed to service provision by an unregulated monopolist.

From a practical perspective, promoting competition in generation requires attracting new firms with independent generation sources into the market and encouraging the trading of electricity across the grid. For the most part, electricity generation would eventually be carried out as an unregulated competitive service. Generation would be supplied both by subsidiaries of traditional local utilities and new independent power supply companies that would enter the generation business and sell power into the grid. Also, power marketers (firms that trade electricity) could provide local utilities with contracts and hedges, thereby offering them a wider range of options for managing the energy demands and price risks of customers in their service areas.

However, from a theoretical perspective the existence of new suppliers in every market may not be necessary to promote the benefits of opening generation to competition. The threat of competition can provide incentives for existing generators to improve efficiency and offer new products. Still, the high cost of entering the generation business may require the physical presence of a competitor, since existing generators know that a potential rival may have a lag time before it is able to provide new supply into the market. Construction delays, permit requirements, and transmission limitations may affect a competitor's ability to offer service.

The second unbundled function is transmission. Transmission applies to the bulk movement of power across high voltage power lines—linking individual utilities to sources of power. In the past, integrated utilities tended to favor building limited transmission networks. These networks would often link a single utility with one or two other outlets for importing or exporting power. They were not designed to serve as universal transmission grids for multi-state regions, since most utilities built their own generation systems with large reserves to serve their peak load requirements. Fundamental to restructuring has been the assumption that an independent entity needs to be established to run the transmission system. The grid "makes the market" and without it, wholesale buyers and sellers will not choose to trade. Without an independent transmission organization (such as an RTO), local utilities cannot be assured of supply and they will still want to establish transmission systems that primarily meet their local needs. If independent generators are unable to access or have uncertain access to the transmission grid, they cannot serve their customers and restructuring is jeopardized. Thus, open

access to a technologically adequate, multi-state transmission system is essential to promoting competitive generation sources.

The third unbundled element is the distribution system. While the transmission system serves as the superhighway for moving bulk electricity, the distribution system can be thought of as the off-ramps and local roads that bring electricity into the homes and businesses of consumers. Under restructuring, traditional utilities often create a subsidiary that is purely in the distribution business. Since it makes little sense to build competing distribution networks, these distribution companies are often state-regulated monopolies that not only have responsibility for the wires that run into an individual home or business, but also for billing and other administrative functions. Even with distribution, it is hoped that by unbundling the function, the true cost of operations for specific classes of customers can be more easily identified and priced accordingly. In doing so, distribution operators will focus on efficiency improvements to serve varying classifications of customers.

Restructuring at the regional level—The Midwest

To date, electricity restructuring continues to be an uneven process. Even states that have expressed similar electricity policy goals, such as improving transmission, reducing noxious air emissions, and attracting new generation, often adopt different strategies. One of the real challenges facing electricity policy in the Midwest is the lack of a consensus on the benefits of opening electricity markets to competition. At first glance, the five states in the Seventh District are extremely heterogeneous in terms of the price of electricity and their interest in pursuing restructuring (see table 3). While Illinois and Michigan continue to press forward with plans to open their electricity markets to competition, Indiana, Iowa, and Wisconsin are taking a decidedly cautious approach. Two areas that the five states can agree on are the need for improvements to the region's transmission grid and the need to account for changes in environmental policy when considering alternatives for future electricity generation.

As figure 3 demonstrates, the Midwest is not alone in this piecemeal approach. Throughout the nation, states are choosing different strategies for pursuing restructuring; and the recent problems in California have slowed restructuring activity in several states.

On the road to restructuring—Illinois and Michigan

Illinois

Illinois took its first steps on the road to electricity restructuring in 1997 with the passage of the Electric Service Customer Choice and Rate Relief Law. The state is phasing in competition and customer choice. Different classes of customers have been given the option of choosing an electricity supplier, beginning with certain large nonresidential customers in October 1999. As of December 31, 2000, all nonresidential customers can pick a supplier, and a watershed will be reached on May 1, 2002, when retail choice will be open to residential customers.[5]

However, some analysts suggest that the start of residential choice in May will be met with very little immediate activity. In the service territory of the state's largest utility—Commonwealth Edison (Com Ed)—residential rate reductions of 20 percent have been ordered. These rate reductions were intended to provide residential customers with benefits of restructuring during the period when nonresidential customers were permitted to choose suppliers. The problem is

TABLE 3

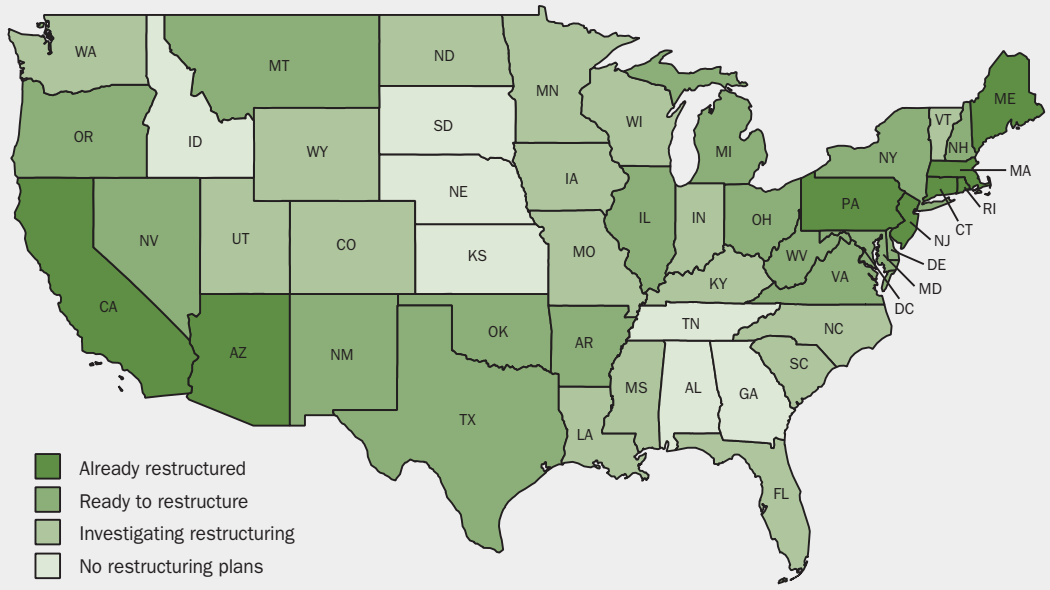
Seventh District energy profile

	Illinois	Indiana	Iowa	Michigan	Wisconsin	U.S.
Exporter or importer	Exporter	Exporter	Importer	Importer	Importer	n.a.
Primary generating fuel	Coal	Coal	Coal	Coal	Coal	Coal
Average electricity price (cents/kWh)	7.46	5.34	6.04	7.09	5.44	6.74
Industrial	5.11	3.95	3.99	5.03	3.86	4.48
Commercial	7.77	6.08	6.67	7.81	5.87	7.41
Residential	9.85	7.01	8.38	8.67	7.17	8.26

Note: n.a. indicates not applicable.
Source: U.S. Department of Energy, Energy Information Administration 1999, *State Electricity Profiles*, available on the Internet at www.eia.doe.gov/cneaf/electricity/st_profiles/toc.html.

FIGURE 3

Status of restructuring of electricity markets



Source: U.S. Department of Energy, Energy Information Administration, 2000, "The restructuring of the electric power industry: A capsule of issues and events," report, January.

that these rate reductions are likely to discourage new suppliers from entering the market, because they will find it difficult to undercut the price already being offered to residential customers.[6]

Although Illinois has made progress in the nonresidential market, statewide performance is at best uneven. A number of new service providers have received certification by the Illinois Commerce Commission as alternative retail electric suppliers. These suppliers have been reasonably successful in securing industrial and commercial customers, particularly in the Com Ed service territory (see table 4). For example, the switching rate for the *eligible* industrial load in Com Ed's territory is 72.5 percent; however, the next highest industrial switching rate is only 19.7 percent in Illinois Power's territory. In five of the service territories, no switching has occurred. The switching pattern for eligible commercial customers is similar.[7] As is often the case in the opening of a new market, suppliers are largely pursuing the best and most profitable accounts. Whether the advantages of choice are reaching all nonresidential customers remains to be seen. An additional issue is whether these switching rates can be sustained. In Pennsylvania, the state's largest utility, Peco Energy, reported losing 44 percent of its industrial customers and 30 percent of its commercial customers to new suppliers when choice was first made available. One year later, Peco had reclaimed many of these customers, leaving their net customer losses at only 4.7 percent for industrial customers and 5 percent for commercial businesses.[8]

Efforts to encourage competition have occurred not just on the supply side of the equation, but also on the demand side. Buyers have formed "collaboratives" and secured their own discounts. The most prominent of these represents a coalition of the City of Chicago and 48 suburban governments. This group signed up with Houston-based power marketer Enron to provide their energy needs, and the group estimated that they would save $4 million per year through the new service provider. However, the announced bankruptcy of Enron in December 2001 led to the cancellation of this contract.

One final positive development in Illinois has been the state's current ability to attract new generation facilities. Illinois is a preferred location for new natural-gas-fired generation, partly due to the presence of major gas pipelines in the state. Currently, 59 plants with a generating capacity of 27,881 megawatts (MW) have either been permitted, are under review, or have been placed in service since 1999.[9] While it is unlikely (and not necessarily desirable) to have all of this generation built, clearly Illinois has not faced significant challenges in attracting investment in new plants. These new plants

TABLE 4

Switching statistics for Illinois

A. Industrial customers

	Switching rate, share of eligible industrial load	Switching rate, share of all industrial load
	(percent)	
AmerecenCIPS	7.5	6.4
AmerenUE	0	0
CILCO	0	0
ComEd	72.5	39.9
Illinois Power	19.7	15.1
Interstate Power	0	0
MidAmerican	4.0	3.6
Mt. Carmel	0	0
South Beloit	0	0
Total	38.8	30.0

B. Commercial customers

	Switching rate, share of eligible industrial load	Switching rate, share of all industrial load
	(percent)	
AmerecenCIPS	30.7	7.1
AmerenUE	0	0
CILCO	0	0
ComEd	48	16.5
Illinois Power	11.6	3.0
Interstate Power	0	0
MidAmerican	20.2	8.6
Mt. Carmel	0	0
South Beloit	0	0
Total	40.3	12

Note: Rates are effective through December 15, 2000.
Source: Electric Light & Power, 2001, *Illinois and Deregulation: A Fresh Update Places the State at the Halfway Point,* March 22.

have the potential for increasing generation competition in Illinois; however, in a deregulated system, they will not be obligated to serve the Illinois market.

Michigan

Michigan is the other state in the District that continues to press forward on restructuring. Michigan faces a slightly more urgent burden, in that the state is an electricity supply importer. Currently, retail market activity in the state appears less developed than in Illinois. Pilot programs where incumbent utilities have made roughly 10 percent of their load available for customer choice have attracted little active interest. For example, as of January 1, 2001, two large utilities—Detroit Edison and Consumers Energy—have made a total of 2,100 MW available to retailers to provide to customers. So far, only 257 MW of electricity is actually flowing from alternative service providers to large customers.[10] The Michigan Public Service Commission (PSC) has expressed concern that a shortage of in-state generation capacity and an inadequate transmission system are responsible for the lack of response from alternative suppliers. The PSC reported that as of February 1, 2001, only ten alternative energy suppliers had been certified and only four of these were actively serving retail customers. The PSC reports that "the pilot programs have demonstrated the importance of transmission in making customer choice effective. Without adequate transmission, new suppliers are unable to secure and deliver power to their customers. The existing transmission system is physically not adequate to support a vibrant competitive market."[11]

Due to the lack of in-state generation, the PSC reported that Detroit Edison and Consumers Energy would need to purchase about 2,900 MW (representing roughly 15 percent of estimated total demand) over the summer of 2001 to meet load and maintain a reasonable operating margin. These structural impediments are limiting options even for customers that are actively interested in receiving service from an alternative provider.[12]

Michigan's transmission constraint has been of sufficient concern that the Michigan legislature mandated that utilities make provisions for 2,000 MW of incremental transmission capacity by 2002. As for the shortage of in-state generation, the PSC reports that 2,166 MW of new generation has gone on line since June 1999. Generators have also reported to the PSC their intention of adding 7,670 MW in the future, based on facilities that are either planned or under construction.

The cautious approach—Indiana, Iowa, and Wisconsin

Indiana

With low power prices derived from coal-based generation, Indiana has been cautious in pursuing restructuring. Policymakers have focused on maintaining the advantage of low-cost power, and Indiana consumers do not appear to be actively interested in a choice of provider. However, California's recent bad experience has led Indiana policymakers to continue to study their options. One policy area of interest to the state is the role of merchant power plants (which appear to

be interested in establishing locations in the state) and trying to establish a more comprehensive energy policy to guide Indiana decisionmakers. In the last several years, over two dozen merchant plants have been proposed, with the state's Public Service Commission approving seven of the plants.

Indiana's interest in expanding generation may be well founded. The state is currently an exporter of electricity and would like to use its combination of low price and relative energy surplus to attract economic development. However, a recent report of the State Utility Forecasting Group (SUFG) found that it has a declining ability to meet its electricity needs and maintain a 15 percent reserve margin. (Because electricity cannot be stored, reserve margins of 15 percent or greater are considered prudent, particularly when transmission limitations might limit access to generation from more distant utilities.) In its 1999 projection estimates, the SUFG predicts a potential deficit of 2,000 MW by 2005 and of 4,000 MW by 2010 (assuming no new generation is added in state). With neighboring states, particularly Illinois and Ohio, actively adding generation and restructuring to encourage competition, Indiana is anxious to maintain its currently favorable status. Indiana officials are currently reviewing proposals for 2,330 MW of new generation.

Iowa

In Iowa, the focus of electricity policy has been on incentives for creating new generation, rather than opening markets to competition. A bill considered during the last session of the Iowa legislature offered indirect incentives for new generation by requiring the Iowa Utilities Board (IUB) to specify in advance the rate-making principles it would use for establishing the recovery and return on investment for any new plants built. Also under the proposed legislation, Iowa utilities signing contracts for power from in-state resources would receive irreversible contract approval within 90 days if the IUB found the contract "reasonable and prudent."

Evidence from the IUB's comprehensive review of Iowa's electricity structure and the implications of restructuring suggests that the state needs to focus on generation. The IUB finds that, based on a projection of annual load and annual load obligation, the largest utilities in the state will move from a surplus of 495 MW in 2000 to a potential deficit of 2,208 MW by 2009. The turning point in the surplus/deficit could come as early as 2003.[13]

Recently, two large utilities have expressed interest in building new generation in the state. MidAmerican Energy announced plans to build a gas turbine plant east of Des Moines that could produce 540 MW of power by 2005. This would be the first new large power plant built in Iowa in 20 years. Another major player, Alliant Energy, is investigating building up to 1,000 MW of new generating capacity in Iowa.[14]

The provision of electricity in Iowa is relatively complex, with a large number of utilities in the state. Large investor-owned utilities accounted for 76 percent of the megawatt per hour (mWh) sales in 1998, while 137 rural cooperative and municipal companies provided the remainder.

Wisconsin

Wisconsin's electricity policy has focused on improving capacity and reliability. While the state's low prices continue to be an advantage, reserves continue to dwindle and transmission bottlenecks have led to concerns about reliability. State policy has not favored sweeping restructuring. Instead, policy has emphasized providing incentives for utilities and independent companies to create new, in-state generation.

State electricity supplies are extremely tight, particularly in the eastern half of the state, according to the Wisconsin Public Service Commission's (PSC) Strategic Energy Assessment for 2001. During summer peak generation months, transmission constraints make it difficult to relieve supply shortages in eastern Wisconsin, even when power is available from sources in western Wisconsin and neighboring states. This grid congestion has left major utilities having to rely on interruptible service contracts to prevent outages. Customers subject to these interruptible contracts have become increasingly dissatisfied with this arrangement, even though they receive lower prices in return for permitting the service reduction. By 1998, transmission limitations had reached a point where the PSC recommended adding 3,000 MW of transmission into the state, doubling the existing transmission capacity.[15]

Generation is also needed. The state has not added any baseload generating units since 1985. Wisconsin has also faced challenges attracting new suppliers. By the end of 1999, the state had only two merchant plants operating; however, the PSC anticipates that merchant plant production could reach 10 percent of the state's generating capacity by 2002. In all, merchant plants could add 740 MW of new generation by 2002.[16]

Wisconsin policymakers have been investigating ways in which the existing regulatory structure can be modified to provide investment incentives while retaining oversight authority. Much like Iowa, Wisconsin is emphasizing adding new rate-regulated generating units and encouraging long-term contracts with in-state independent generators. Proposed policy options include increasing regulatory certainty for recovering new investments, for example by raising the permitted return

on capital investment. These are still proposals, but like Iowa, Wisconsin is trying to chart a path that will increase capacity and transmission quality, without reducing direct oversight of the electricity business.

Electricity restructuring at mid-term—What have we learned?

Electricity restructuring is a work in progress. New markets and mechanisms will not form overnight and the transition period has already proven to be bumpy. California's experience with restructuring has led many states to reconsider whether restructuring can produce the benefits of lower consumer prices, more efficient generation, and product innovation often touted by proponents. Given the balkanized nature of the U.S. electricity system, it is understandable that establishing a national electricity policy has proven difficult. However, early programs in the electricity system and experience from the deregulation of other network industries (telecommunications, trucking, airlines, and natural gas) have produced some useful lessons for policymakers to consider.

For the purposes of this article, I group the experiences from restructuring into three broad categories. The first category focuses on the unique features of electricity that directly influence its market structures. The "uniqueness" of electricity limits its treatment as a standard commodity and influences the set of policy goals that can be achieved through restructuring. The second category considers the need to invent or reinvent institutions to govern the industry as it restructures. For existing regulatory bodies, this will mean adding new responsibilities and shedding old authority. Also, entirely new institutions (RTOs in particular) will need to be created and provided with the resources, authority, and mission to manage separated functions such as transmission. The final category addresses issues of market structure and design. This has two components. First, regulatory bodies are facing transition costs as they adapt to dealing with restructuring and the introduction of markets. Second, consumers are facing their own transition costs as they are exposed to a less regulated electricity system.

Category 1—Understanding electricity as a unique commodity

In some important ways, electricity is unlike other commodities. It is a modern necessity; we rely on it to provide light and heat, to fuel commercial and industrial production, and to run most appliances in the home. Much like water, electricity generally carries a low price, has a high value to the consumer, and offers no short-run substitutes. The critical role of electricity has led to a regulatory policy favoring the development of excess capacity to ensure reliability of service, even when this has had the effect of inflating the price.

Second, electricity has certain physical properties that make it different from other commodities. Primarily these have to do with difficulties in storing or rapidly adding new capacity. Significant supplies of electricity are almost impossible to store and electricity needs to be consumed when produced. This characteristic, combined with the inelastic demand of customers, creates high marginal prices when there is a shortage of electricity in a market, unless power can be imported through the grid. Assuming that a utility has no other choice but to meet its load obligation through the spot wholesale market, it is fully exposed to paying whatever price the market will bear for a commodity that is consumed immediately.

In addition, it is difficult to create new electricity capacity quickly. New power plants in most states require 18 months to 24 months to site and build, and local opposition to construction often lengthens the process even further. Moreover, new power plants require very high capital outlays and can be seen as risky investments in the restructured electricity market. The decision to build a plant is predicated on the cost of key variable operating costs (fuel in particular) and an assessment of the price that can be charged for electricity, which is often dependent on regulatory decisions. New generators are often providing reserve, back-up power, rather than meeting the daily base-load needs of a given service area. This also introduces uncertainty into the decision to add new generation.

These factors—the inability to economically store electricity and the inability to create new generation quickly—create the conditions for high prices in the spot wholesale market and can provide certain sellers of electricity with the opportunity to charge very high prices for power. To avoid very high transition costs associated with restructuring, state policymakers need to ensure either that adequate reserves exist or that restructuring will create the conditions for adequate reserves.

Another special feature of electricity is that it needs to be delivered over an extensive physical grid. The transmission grid is the physical market for trading electricity, making issues of grid reliability, capacity, and access critical in creating the conditions for competitive market operations. Assessing this infrastructure requires integrating several levels of analysis. First, what is the current condition of transmission and generating assets? Can steps be taken to improve the operation of the existing facilities? How easy is it to access the grid and efficiently transport electricity to where it is needed? Recently, electric power forecasters

have questioned as inadequate the amount of new transmission capacity that is planned in the system. Second, will new technologies change the need for the type of generation and transmission that is needed? Some analysts suggest that micro-generation, fuel cells, and other new technologies may allow an increasing number of consumers to generate electricity in their homes and businesses. If this is true, building large generation plants and making extensive upgrades to the grid may be less important than has traditionally been assumed.

The performance of the transmission grid (as we have seen in the survey of the Seventh District states) can undermine the development of healthy wholesale markets and limit the appeal for new companies to develop new operations in Midwest states. Blackouts in Chicago and power problems in eastern Wisconsin have frequently been linked to transmission bottlenecks rather than a lack of adequate generation. The policy problem is that many decisions regarding transmission and the construction of new generation need to be conducted in coordination with actions in neighboring states. Improving the intrastate grid is certainly important, but it will not fully substitute for the need to carry out such a policy in concert with activities in neighboring states. A well-functioning grid can reduce the need for building excess generation capacity, if energy can reliably be made available through transmission. For example, in Wisconsin's forecast of energy needs, the Public Service Commission makes differing recommendations for generation needs and reasonable generator reserve requirements based on assumptions about the future performance of the grid. With a well-functioning grid, the traditional reserve requirements of 15 percent are adequate, but without any improvements in grid performance, recommended safe generation margins for utilities facing poor grid connections rise to 30 percent.[17]

Based on this assessment of the infrastructure for delivering electricity and the conditions that make electricity a "special commodity," policymakers need to have a clear set of restructuring goals. Artificially reducing the retail price of electricity in order to gain support from various constituent groups should not be the sole motivation for restructuring. The price of electricity should reflect market factors. If competition introduces efficiency that lowers prices while maintaining other important policy goals, such as reliability and adequate reserves, lower prices can be a welcome outcome.

In testimony before the Senate General Administration Committee, economist Paul Joskow suggested that "… deregulation is not a goal in and of itself. The goal is to create well functioning competitive markets that perform better than the regulated structures they replace."[18] The real benefits of restructuring will become apparent when fully functional markets are operating. This will take time. Frequently, electric restructuring is presented as a policy designed primarily to reduce the current price paid for electricity. Often this is motivated by states facing the highest electricity prices being the most interested in opening their electricity market to competition. It is no accident that in the Seventh District, Illinois and Michigan, the high-price states, are pursuing restructuring, while the three low-price states are hesitating. This interest in promoting competition has been pressed by large industrial customers that would expect to pay significantly less for power in an open wholesale market with multiple suppliers bidding for their business. Under fixed regulated retail tariffs, industrial customers often argue that they are subsidizing the residential market. However, an immediate policy objective of reducing the price paid for electricity may impede valuable longer-term policy goals, such as encouraging innovation and efficiency in generation and promoting product customization. For example, many high-tech firms are more interested in electricity that can be provided with complete redundancy (that is, 100 percent back-up capability) and is of the highest quality, not subject to transmission or distribution disruptions. Clearly, the opportunity to purchase this type of specialized, premium product may be of greater interest to certain classes of customers. Similarly, some consumers may want to promote environmental goals and may be willing to pay a premium for electricity from renewable sources. For example, in the Pacific Northwest, the Bonneville Environmental Foundation and the Climate Trust of Portland are marketing "green tags" to utility customers. These tags sell for $20 and the proceeds are used to purchase power from a renewable source such as wind power, thereby allowing individual customers to purchase offsets to traditional energy sources.[19]

Beyond the often-repeated goal of reducing prices, longer-term goals of establishing competitive markets in electricity should include establishing incentives for investments in more efficient power plants, stimulating the introduction of new technologies (such as fuel cells), encouraging innovation in both supply and demand-side management, and even providing incentives to promote needed investments in transmission and environmental mitigation.

Policymakers clearly face some political challenges as well, which may lead some states to adopt short-run policies (such as mandatory price caps and price

cuts for residential customers) that would in fact prevent changes in wholesale markets from being reflected in retail markets. The tradeoffs between lower prices, increased investment, and even related environmental goals of lower emissions will be made in a political context. Ideally, the political process will set the policy targets and leave the methods for achieving these targets efficiently to market mechanisms. It is also important that the institutions charged with implementing and overseeing the restructuring process be insulated from political interference. Ultimately, this requires an electricity policy characterized by integrated resource planning, a complete understanding of technology and efficiency tradeoffs, and the flexibility to make mid-course corrections as changes in supply and demand conditions require.

Category 2—Inventing or reinventing institutions and roles

We know by now that electricity restructuring is a complicated business. Existing institutions such as the state public utility commissions and FERC will have new roles in guiding restructuring and they will be asked to reduce their authority in areas where they have traditionally held jurisdiction. Even more difficult will be creating new institutions, the proposed RTOs, market surveillance committees, and electricity trading systems to support restructuring. Both the traditional regulators and these new institutions need to be vested with the resources, incentives, and authority to carry out their missions. They need the resources to actively monitor the markets under their authority and the data to know what is driving these markets. Governance issues include clarifying overlapping jurisdiction and decisionmaking authority. Resource issues include staffing, staff training, and sufficient data to monitor an industry that is undergoing profound changes. California's experience again presents a telling lesson. For example, Governor Gray Davis acknowledged that when it came to negotiating for power sales to the state, the state's negotiating team faced a circumstance similar to "a tee-ball team playing the NY Yankees."[20] While this was an extreme situation, it underscores the difficulties that may arise when the state government is forced to play an unfamiliar role.

To date, the formation or reinvention of these institutions has been a difficult process; and the related uncertainty may be discouraging potential infrastructure investments. The most obvious example in the Midwest has been the attempt to form an RTO. Most of the region's major utilities had joined the Midwest Independent Systems Operator (MISO) and assumed that this organization would become the RTO for the region. However, internal issues led to many of the largest utilities withdrawing from MISO and establishing the Alliance RTO. This group subsequently identified the British firm, National Grid, as its grid operator. However, it is unclear whether National Grid would actually own any of the transmission infrastructure or would simply serve as the system operator. If the traditional utilities maintain their ownership of their existing transmission assets, it is unclear how investment decisions will be made or coordinated. These developments also call into question how easy it will be for competitive generators to access the grid on equal terms. Adding to this confusion is FERC's recent request that the geographic boundaries of the RTOs be expanded in an effort to develop a national grid. FERC has suggested that MISO, Alliance, and the Southwest Power Pool should consider combining into a super-regional RTO.[21] (On December 19, 2001, FERC approved MISO as the RTO for the Midwest. The MISO transmission area will operate in 20 states. In its action, FERC suggested that the Alliance organization could operate as a member of MISO.)

Even if the issue of what organization is running the RTO is resolved, the potential functions of the organization need to be considered. One white paper produced by the Electricity Policy Research Institute examining power issues on the West Coast produced a list of recommendations for improving electricity operations. The study suggests that RTOs should have either primary or shared responsibility for addressing a significant array of issues, including repairing dysfunctional wholesale markets; generating standardized regional energy information; and implementing a "whole system" reliability-centered maintenance capability. This whole-system approach would include assessing the equipment health for vital components; initiating comprehensive, region-wide transmission risk analysis; creating a seamless real-time exchange of information among regions; coordinating training of grid operating personnel; developing power-flow technology for system reservation and scheduling; and establishing regional authority for siting and cost sharing.[22] Clearly, this is an ambitious agenda for an organization that is still being developed.

Finally, the formation of large, multi-state RTOs suggests that FERC, and not the state public utility commissions, will need to play the major regulatory role over transmission issues. Even this decision is not clear-cut. Following the summer 2001 meeting of the National Governors Association, the governors agreed to work with the U.S. Department of Energy and other federal agencies to improve transmission, but made it clear that the states still wanted to maintain their traditional policymaking role over

transmission. Specifically, the governors issued a statement to the effect that "governors oppose preemption of traditional state and local authority over siting of electricity transmission networks, but governors recognize that situations exist where better cooperation could improve competition and reliability. Governors are willing to engage in a dialogue with the federal government and industry to address these situations in a manner that does not intrude upon traditional state and local authority."[23]

A final governance issue has to do with the oversight of municipal and cooperative utilities. These utilities, which are not major suppliers of electricity in most states, are often self-governed. While larger investor-owned utilities are subject to regulation by state utility commissions and FERC, it is unclear whether these smaller players should be brought under the same regulatory structure.

Category 3—Market structure and design

Transition costs for regulators

Industry observers assume that the introduction of competition into the generation component of the electricity system will best be accomplished through market mechanisms. The eventual goal of promoting unregulated (or at least minimally regulated) competitive generation is to promote cost efficiency and greater diversity of generation resources. Yet, the introduction of markets provides another set of challenges. These challenges can be understood across three dimensions. The first dimension relates the uniqueness of electricity as a commodity to the implications of using markets to deliver electricity, as discussed earlier. The second two dimensions consider two sets of transitions costs of moving to a market structure. The first set of costs relates to the actions and adaptation (and potential rigidity) of regulatory bodies and market participants in responding to the unbundling of electricity service. The second set of transition costs relates to the implications of market structures for end-users/consumers of electricity.

I discussed earlier how the physical properties of electricity create certain challenges to establishing smooth operating markets. The inability to store or rapidly create new capacity, as well as physical limitations of the grid as the market trading system are all factors that must be accounted for in successfully restructuring electricity. Another important change that is brought about by moving to a market structure is the potential lack of incentive to provide large generation reserve margins. In the old regulated system, the utility would be willing to build surplus capacity into its generation plans. Since the regulator permitted a rate structure that allowed the utility to recover the cost of this extra capacity (even if it went unused), there was little risk involved in carrying a large reserve margin. In moving to an unregulated market structure for generation, carrying reserve capacity (particularly when the generator cannot store the power) clearly makes little sense from the generator's perspective. It is therefore not surprising that states that have been moving toward restructuring have seen reserve margins decline, so that supply and demand more closely match each other.

Another consequence of moving to a more market-based electric system is that the new market structure may provide opportunities and incentives for suppliers to exercise market power. Market power can be understood as the ability to raise market prices through unilateral action so as to profit from the price increase. Concern over suppliers exercising market power is one of the potential transition costs faced by regulators. To address these concerns in the wholesale market, FERC only allows suppliers that can demonstrate that they do not have market power to sell in the market and receive the market-clearing price. Suppliers that cannot demonstrate an absence of market power are limited to charging the cost-of-service rate set by FERC.[24]

Establishing whether a firm has market power is critical in determining whether prices being charged in newly created electricity markets are the product of manipulation or genuinely reflect the interaction of supply and demand. In the case of the California market experience of recent years, it was often alleged that certain suppliers would withhold generation or use other timing and bidding techniques to receive extraordinary prices when it was known that utilities would have to make purchases in the spot market. Determining the prospective market power of an electricity supplier is a very difficult business. Attempts by FERC to define market power have been met by skepticism. Frank Wolak, a Stanford University economist who serves as chair of the Market Surveillance Committee of the California Independent System Operator, points out that market power is often incorrectly estimated based on the concentration indexes applied to geographic markets. These geographic boundaries fail to account for the fact that electricity must be provided to final customers over the existing transmission grid. Limitations in the grid can make differences in the bidding, scheduling, and operating protocols of the market crucial in determining whether a supplier can exercise market power. Work by Wolak, Borenstein, and Bushnell (2000)[25] measured the extent of market power in California since 1998,

and the Market Surveillance Committee has contributed a number of reports on the subject. By the summer of 2000, the committee found that average monthly prices being charged for June were 182 percent above what would have been expected if no generator was able to exercise unilateral market power.[26]

Competitive generation and supply will change the incentives and behavior of many firms in the electric supply business. In the case of traditional integrated utilities, the spinning off of generation into unregulated affiliated companies raises the expectations for shareholders that these generation companies can become profit centers for the parent company. On the one hand, increasing the importance of profitability as a measure of success for the generation company should promote efficiency. On the other hand, it also raises the incentive for generators to take advantage of market conditions to receive the highest price for their production. It is important to recognize that the "public service" ideal that once guided utilities will be de-emphasized once generation is treated as a commodity. Studies by California's Independent Systems Operator provide evidence that generators did withhold supply in order to bid up market prices. During the fall and winter of 2000–01, there were nearly four times as many scheduled and unscheduled plant shutdowns as in the previous year. While some of these could be attributed to breakdowns in older plants that were forced to run at higher capacities than intended in order to avoid blackouts and brownouts, some shutdowns seemed to be more strategic.

This motivation is even more obvious in the case of independent merchant generators. An example of this occurred in the California market in January 2001. In the latter half of the month the California grid operator faced a series of conditions that made the likelihood of an energy shortage in the state highly probable. A combination of unfavorable weather, a lack of supply from traditional reserve supplies from northwestern states, and a malfunction at a 1,000 MW plant in the state meant that the grid operator had to scramble to find power. Eventually, the operator found a California merchant plant that was willing to offer power, but only at the record price of $3,880 per mWh. The grid operator ended up buying the power, and this situation demonstrated the ability of this single supplier to set the price in the market. In justifying the record price charged, the merchant generator admitted that the price was less related to the plant's cost of generating power than the risk premium it was charging for selling into the financially shaky California energy market. (As it turned out, the generator never received the $3,880 per mWh. First, FERC investigations into the price charged found that the generator had overcharged for the electricity and reduced the price to $273 per mWh. In fact, to date the generator has only received payments equaling $70.22 per mWh, due to the inability of the purchasers to make good on their debts.)[27]

The Independent Systems Operator's study also demonstrated how independent generators could use bidding to influence the price in the wholesale market. It was estimated that the combination of withholding supply and strategic bidding behavior accounted for one-third to one-half of the increase in prices in the California wholesale energy market. This added roughly $6 billion to the costs California consumers had to pay. In the case of bidding behavior, the study revealed that the rules of the hourly auctions provided an opportunity for generators to manipulate prices to their advantage. Under the terms of the hourly auction, generators would offer batches of energy at various prices. The system operator would then rank the bids according to price, and the price in the market was set at the bid price for the last unit of electricity needed to meet the demand on the grid. At this point, all generators in the auction would receive the price that had been paid for the last unit. The concept behind this bidding structure was to treat the electricity supply like any other commodity, where everyone in the market would receive roughly the same price for providing a homogenous good. Over time, generators became very savvy about taking advantage of this structure when it seemed likely that supply would run short. Essentially, most bids would be offered at prices that roughly reflected the cost of generation plus some reasonable margin. However, the final units would be bid at an extreme premium, sometimes at ten times what the normal price would be. If all of the bids for these final units of supply came in at these prices, the operator had no choice but to accept this price in order to meet load. At this point, because of the terms of the market, all of the supply bid that day would receive this high price. While it has not been shown that this bidding behavior involved collusion among the generators, it is clear that this auction system provided an opportunity for savvy bidders to take advantage of the process, and it appears that they did.[28] Critics of California's restructuring plan have suggested that permitting the use of long-term contracts and other hedges would have made it is far less likely that the prices bid would have been at such exaggerated levels, since spot shortages would have been less frequent.

Finally, the role of power traders in markets needs to be understood. These firms provide financial options to electricity markets, but are not in the

business of building or owning generation facilities. Firms such as Dynegy are well known as power traders but, increasingly, regulated utilities carry out trading activities through unregulated subsidiaries of their holding company. In an ideal world, this can help utilities and customers manage risk. For policymakers, marketers are often a new institution to deal with. Utility commissions often lack the staff to monitor the behavior of traders in the electricity market for signs of collusion or unfair practices. Policymakers need to understand that the purpose of these firms is to make money through trading, not to serve as a public utility. In this regard, oversight of these firms may best be accomplished through the same mechanisms that govern other commodity trading operations. However, most states appear to lack such a structure or a real understanding of how to deal with electricity traders. In the case of California, for example, market problems identified by the state's Market Surveillance Committee were largely ignored.

Transition costs for consumers

What are the implications of electricity restructuring for consumers? First, consumers need to understand that opening markets will expose them to both the advantages and disadvantages of market pricing. In the past two years, this increasingly has meant dealing with a commodity with high price volatility. Electricity consumers are not used to dealing with market risk, since the regulated electricity system had firm tariff-based prices. Exposing consumers to market-based (or even real-time) prices is a natural consequence of moving to a market system. However, in many cases, states are protecting their residential and small business customers from price volatility by freezing electricity prices for a transition period. This presents several problems. Frozen retail rates mean that consumers are not exposed to the underlying dynamics that are being reflected in the deregulated wholesale market. California's experience has shown the problems that can result from this approach. Because California's consumers were insulated from market risk and volatile prices, they never received the appropriate price signal that would have caused them to immediately reduce consumption when electricity prices spiked. This eventually led to the financial insolvency of the state's two largest investor-owned utilities. Eventually, Pacific Gas and Electric and Southern California Edison ran up $9 billion in debt, purchasing power in the spot market.[29] Only much later did the California Public Utility Commission allow these two utilities to charge higher prices for electricity and, by then, Pacific Gas and Electric Company had filed for bankruptcy protection and Southern California Edison had gone to the state legislature asking for assistance.

Efforts to set prices for certain classes of customers during a transition period have other shortcomings as well. If the price is set artificially low, new entrants to this competitive market will not appear, since the margin will not be sufficient for them to capture customers. This will undermine the development of a competitive market. On the other hand, if the price is set too high, consumers may be paying too much in return for stable electricity prices. Instead, it would make more sense to allow prices to reflect market fundamentals. The downside is the resulting price volatility faced by end-users. In order to protect risk-averse consumers from being fully exposed to price swings while these markets develop, risk management tools (hedges and long-term contracts) can be used. Consumers who have grown accustomed to a firm price for their electricity bills can still be provided with this option in a deregulated market. The distributing utility can offer a customized product that protects the consumer against volatility by offering a firm price that has an "insurance" premium built into the rate. Even now, many utilities offer customers fixed monthly payments that protect them from high electricity bills caused by seasonal conditions.

Volatile prices can be an essential element in encouraging more efficient demand-side management. Pilot programs in real-time pricing demonstrate that consumers will respond to price spikes by reducing consumption.[30] In testimony before a Senate panel, Joskow went as far as to suggest that the default service option for larger commercial and industrial consumers should be purchasing electricity at real-time prices. He argued that the use of real-time pricing for these more sophisticated customers would introduce demand elasticity into the wholesale market and this, in turn, would dampen price volatility and help mitigate supplier market power.[31] Providing more opportunities to manage peak load needs can produce a more efficient electricity system. Allowing price signals to be felt can be an important motivator in improving demand-side management programs.

Another transitional cost to consumers is electricity reliability. In the bundled service, rate-regulated, historical model for providing power to the consumer, the blended tariff rate ensured that investments would occur in all aspects of electricity provision—including customer service and reliability. Once the service is separated into three components, the low-profit regulated portions of the business (distribution in particular) may not attract needed investment, which may impair reliability and even service quality. This has

been a frequent complaint in telecommunications restructuring, where once-regulated local phone companies have been allowed into open markets. Once in these markets, the company pursues the most profitable segments of the business, often to the detriment of investing in basic service.

Conclusion

Electricity restructuring is at a crossroads. Experience to date has brought into focus the difficulties involved in restructuring the industry efficiently through a combination of regulated and deregulated structures. The recent experience of California and the number of issues complicating this transition would be of less concern if it weren't for the fundamental role that electricity plays in supporting modern society. There are still good reasons to believe that electricity restructuring can fulfill its early promise. However, as California has demonstrated, electricity restructuring must be fully thought through and carefully crafted. Policy missteps can lead to unintended costs that will be borne well into the future. At a minimum, electricity restructuring requires a clear set of policy targets that establish goals for system efficiency, investment, and prices. Once these goals are established, institutions must be designed and equipped to meet them and, importantly, must be protected from political interference while they pursue these objectives.

NOTES

[1]This policy preference favoring geographically defined, integrated utilities was established in the Public Utility Holding Company Act of 1935.

[2]U.S. Department of Energy, Energy Information Administration (2000), p. 16.

[3]U.S. Department of Energy, Federal Energy Regulatory Commission (1999).

[4]U.S. Department of Energy, Federal Energy Regulatory Commission (2001).

[5]Illinois Commerce Commission (1999), p. 2.

[6]Cvengros (2001), updated August 1.

[7]Davis (2001), Illinois page.

[8]O'Grady (2001).

[9]Cvengros, op.cit.

[10]Ibid.

[11]Michigan Public Service Commission (2001), p. 5.

[12]Ibid.

[13]Iowa Utilities Board (2000).

[14]DeWitte (2001).

[15]Wisconsin Public Service Commission (1998), p. 2.

[16]Wisconsin Public Service Commission (2000), p. 2.

[17]Ibid., p. 4.

[18]Joskow (2001), p. 8.

[19]Knight-Ridder Tribune Business News (2001).

[20]Smith and Emshwiller (2001), p. 5.

[21]U.S. Department of Energy, Federal Energy Regulatory Commission (2001).

[22]Energy Policy Research Institute (2001a), pp. 5–6.

[23]National Governors Association (2001), p. 5.

[24]Wolak (2001), p. 4.

[25]Wolak, Borenstein, and Bushnell (2000).

[26]California Independent System Operator (2000).

[27]www.washingtonpost.com, August 18, 2001.

[28]Pearlstein (2001), p. A9.

[29]Ibid.

[30]Energy Policy Research Institute (2001b).

[31]Joskow (2001), p. 14.

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