A Primer on Electricity and the Economics of Deregulation

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Introduction

Until the onset of the California electricity crisis in summer 2000, all appearances were that electricity deregulation was proceeding satisfactorily and could soon be added to the list of industries successfully deregulated, including airlines, telecommunications, natural gas pipelines, trucking, and railroads. During summer 2000, the wholesale price of electricity in California shot from an average of about $30 a megawatt (MW) hour to over $150 a megawatt hour with prices in some hours reaching $750. Since the California debacle, the electricity deregulation movement has stalled. Further skepticism was fueled by the power outage in August 2003 that crippled much of the Northeast. Policymakers, consumers, producers, and academicians have been reassessing the question, "Electricity deregulation—where to from here?" This volume is intended to provide policymakers and interested citizenry with an answer to this question. It is the result of a Bush School conference on electricity deregulation in April 2003 at the George Bush Presidential Conference Center at Texas A&M University. The conference brought together the leading academic researchers, key policymakers, and influential leaders from industry.

The contributors to this volume are to be applauded for writing very lucid, nontechnical explanations to some phenomena that defy simple explanations. Even though most of the papers are by economists, who by nature are enamored with mathematical equations, the contributors have shown amazing restraint. But before proceeding to chapter 1, this introductory chapter provides a primer on electricity in order to explain how economists think about deregulation and to preview the contributed papers.

Electricity—A Natural Monopoly?

For over a decade, the electricity industry in the United States and elsewhere has undergone fundamental change. Markets have been created to trade wholesale power, enabling powerplant owners, energy traders, and consumers to buy and sell power on the open market. Now a company need not be a utility to enter the market, construct a powerplant, and sell power on the open market. In addition, many consumers are allowed to choose their own electricity provider.

Today's markets for power stand in stark contrast to the structure of the industry just over a decade ago. Until quite recently, the electricity industry in the United States was typified by a number of vertically integrated companies, while in Europe, state-owned enterprises were dominant. In the United States, the production, transmission, and distribution of electricity were consolidated into vertically integrated firms that were highly regulated on the prices they could charge and investments that could be made. Both technological and legal changes have contributed to restructuring of the industry.

Historically, the economic rationale for such a structure was that electricity production was a natural monopoly. A natural monopoly is simply the case where a single firm can produce the total market output at a lower cost than can a collection of individual competitive firms. Each sector of the industry—the generation at powerplants, the high-voltage transmission of power, and the local distribution and metering—has natural monopoly characteristics. Economies of scale in generation coupled with small localized pockets of demand and substantial line losses from long-distance transmission meant that generation plants were best located near individual market centers. Scale economies in transmission again supported building single high-voltage lines rather than multiple low-voltage lines. At the local distribution level, it clearly made sense to have only one local distribution grid rather than multiple lines strung about from competing generators. Thus single vertically integrated firms were ideally suited to serve the various isolated pockets of demand.

Even though a single firm may have been able to serve a market at lowest cost, there remained the problem that an unregulated monopolist would charge too high a price and produce too little, thereby sacrificing economic efficiency. Here, the standard economists' prescription—to grant single franchises and empower a regulatory commission to set prices—was widely adopted in the 1920s. While in principle there were a variety of pricing schemes a regulatory commission could employ, rate-of-return regulation often was adopted. Under rate-of-return regulation, the administered price was set so as to cover the firm's operating costs and reward its investors with a fair rate of return on the capital invested. In effect, prices are set roughly equal to average cost.

The growth in demand and technological advances presents a very different picture today. Particularly at the generation stage, there is no evidence of natural monopoly today. In 2000, U.S. per capita electricity consumption stood at 12,158 kilowatt hours per year as contrasted to only 609 per capita kilowatt hours in 1930. Besides the growth in the overall size of the market, technology has favored broader regional rather than local markets. The minimum efficient scale of new generators of several hundred megawatts or less fueled by natural gas is much smaller than the minimum efficient scale of the large thousand megawatt coal and nuclear units favored in the past. Advances in high-voltage transmission make it possible to transport electricity over a thousand miles. Sophisticated computer systems allow utilities to integrate their operations, which facilitates wholesale trading. These changes have increased the potential geographic scope of wholesale generation markets.

Several legal changes have made it possible for competition in the wholesale market of electricity generation to take off. Prior to the mid-1980s, independent power producers faced huge barriers to entry. Suppose there were a potential entrant who wanted to generate cheap power and sell it to either the local utility, another utility, or some retail customers. This potential entrant faced several problems. First, almost all end users were served by utilities who were under no obligation and had no incentives to purchase power from the entrant. Second, utilities owned the transmission network that the entrant needed to transport the power and did not have incentives to sell transmission services. A sequence of legislation and regulatory rules in the 1980s and 1990s effectively mitigated these problems and allowed both independent power producers and other utilities to compete in the merchant generation sector.[1] For this reason, when economists talk of "electricity deregulation," they are most likely talking about deregulation of the generation activity.

At the transmission stage, the case for natural monopoly and continued regulation remains relatively strong. The costs of acquiring long-distance transmission right-of-ways have been rising sharply because of increased environmental, health, and aesthetic concerns. Consequently, ownership of existing right-of-ways enjoy substantial first-mover advantages. Also, there are economies of scale in transporting electricity. The first 345-kilovolt line was built in 1953. By 2000, it was common to see lines with a rated capacity of 345 kilovolts with some as high as 750 kilovolts. Interconnected networks continue to grow and enable trading possibilities because transmission costs, while rising with distance, often only constitute a small fraction of the final retail price. Expansions of the transmission network involve substantial fixed costs that must be allocated among the many generation companies that benefit from them. And, finally, the physics of power flow create externalities and income transfers that make it problematic for the market to operate the existing transmission network or invest in new transmission assets.

At the local distribution stage, there is no opposition to the notion of natural monopoly. Imagine a local distribution network with ten different companies, each with their own distribution lines strung around on their own light poles. The fact that local distribution is a natural monopoly does not, however, preclude retail competition for consumers. Retail electricity providers can agree to supply local consumers and simply pay the local distribution company for use of the distribution grid. Likewise, retail providers can contract with generation companies, pay regulated tariffs for transmission and local distribution, and sell power to commercial, industrial, and residential end users.

Thus electricity generation and retailing would appear to be prime cases for deregulation where competitive markets could function quite satisfactorily. Deregulation could reduce operating costs of current generating plants, create incentives to invest in new efficient generating technology, and facilitate the adoption of new energy services by consumers. Thus, the standard economists' policy prescription would call for deregulation of electricity generation and retail distribution, leaving transmission and local distribution regulated.

This standard prescription is something one might hear in an undergraduate economics class. However, this prescription ignores many economic, legal, and political complications that are crucial to the success of deregulation. Deregulation does not consist of simply removing existing regulatory infrastructures. Rather, certain elements of existing regulation must be replaced with new institutions and rules designed to provide competitive and reliable electricity services. These complications and design decisions are the topics of this volume.

Design Choice for Deregulated Electricity Markets

Why is Electricity Special?

Electricity has special physical characteristics that make electricity markets different from most other commodity markets. Electrical energy is injected into the transmission grid by all generators and withdrawn by all end users. There is usually no way to identify the power generated by producer A to match with the power utilized by consumer B. One can think of the electricity grid as a big pond with producers putting water into the pond while consumers are simultaneously withdrawing water from the pond. However, the injection and withdrawal of energy must be carefully regulated. Electricity cannot be stored economically so the amount generated at every point in time must equal the amount consumed. The characteristics of the delivered power must be carefully maintained. In order to maintain the frequency within a certain narrow band of tolerance, the quantity injected must closely match the quantity withdrawn moment by moment. To extend the pond analogy, it is as if producers must fill the pond at the same rate consumers withdraw from it. The level of the pond must be nearly constant at every point in time for the system to operate properly.

Contrast this with a typical commodity market. In most markets, bilateral transactions between buyers and sellers coordinate the flow of goods, and no central coordinator is required. For example, the lettuce market has no need for central coordination. Lettuce farmers can independently contract with distributors and grocery stores to sell their produce. Adam Smith's "invisible hand" creates a decentralized coordination of supply and demand. It is true that lettuce has limited storage, so supply must roughly equal demand at each point in time. However, if too much lettuce is produced, excess supply can be freely disposed. If too little is produced, most consumers will get the lettuce they demand, but a few will substitute to other vegetables. But electricity doesn't work this way. In electricity, supply and demand imbalances cannot so easily be accommodated and could cause disruptions to the entire delivery system. A system operator must coordinate schedules of generation, load, and power flow, and balance deviations from expected supply or demand. In effect, Adam Smith's invisible hand is hardly invisible for electricity markets. As we discuss later, the central coordinator's job is complicated by the highly variable nature of electricity demand, which varies substantially from one hour to the next. Air conditioning in the summer and electric heating in the winter can cause demand or "load" to vary by well over 50 percent over a twenty-four-hour period in some parts of the United States. Anticipating the load requirements over a twenty-four-hour period is a nontrivial task given the variability in temperatures.

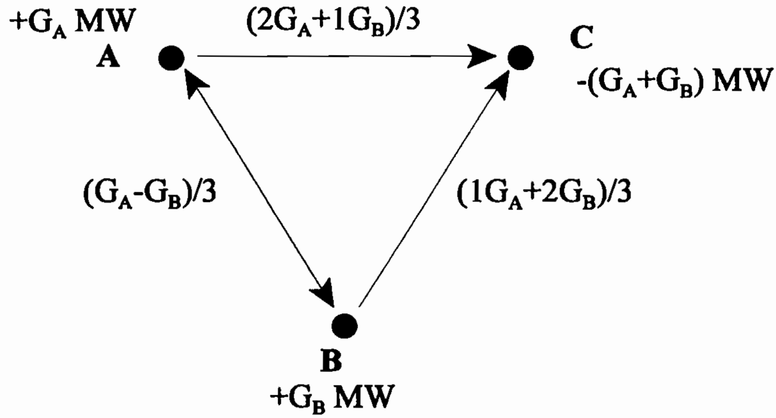
These characteristics have implications for both the type of markets that need to be organized and the competitiveness of those markets. The system operator must keep account of all trades *before they occur* to ensure that supply and demand will balance and create markets to adjust for contingencies such as a generating unit or transmission line going down. Restructured power systems require markets for reliability services such as generating units that can quickly increase or decrease power to adjust for unexpected demand shocks or outages. These reliability services are called ancillary services.

Restructured power systems will require the market to provide adequate reserve capacity and ensure that extra generating capacity is always available so that the lights stay on. Reserve capacity protects against risks posed by events such as unexpectedly hot summers, major plant outages, or dry years with low hydroelectric supply. Because blackouts can impose large externalities on the economy, the provision of reserve capacity has important public good characteristics. If there is no separate market for extra installed capacity, private generators are not likely to build sufficient capacity because the additional units would rarely be utilized and, when utilized, undercompensated by the market for energy. Because generating plants can take several years to build, special markets for installed reserve capacity may be necessary to incentivize the construction of generators that only operate during a limited number of critical hours each year. This problem is analyzed by Shmuel Oren in chapter 10.

The central coordinator can take an active or semipassive role in the market. At one extreme, the central coordinator can function as a market maker and serve as a central exchange for most transactions as in the initial UK. and California markets. At the other extreme, as in Texas, the operator accepts schedules of generation and load from parties that negotiate trades bilaterally. In this more passive role, the central coordinator acts solely as a system operator to ensure that the system remains in balance. However, even in this semipassive role, the system operator conducts a real-time market for energy and ancillary services to ensure the system is balanced within operational parameters. These markets take the form of auctions. In these auctions, the system operator accepts the lowest-cost bids to ensure supply equals demand subject to constraints on the operating characteristics of the generators and the flow of power through the transmission grid.

This task of centrally coordinating the market is further complicated by the fact that trades are location specific. A local utility withdraws energy from the power grid at specific locations, and generators inject energy at specific locations. The "transportation system" for electricity is more complex than the

Figure 1. Supply and demand in a three-node world



transportation of other commodities. In particular, the physical laws of electricity known as Kirchhoff's laws govern how electrons flow in a transmission grid. These laws of electron flow imply that an injection or withdrawal of energy from any point in the network affects the system at every other point. These network externalities have important consequences for both the technical operation of the network and the efficiency of the market in promoting optimal incentives for the efficient operation and investment of generation and transmission assets.

To see a simple example of the flow of power on a transmission grid, consider the network depicted in figure 1. Suppose the transmission network has three nodes with generators (supply) at nodes A and B and load (demand) at node C. G_A MW are injected at node A, G_B MW are injected at node B, and load withdraws $(G_A + G_B)$ MW at node C. For simplicity, assume that each line is equal length and has the same electrical impedance (resistance).[2] Thus, for flows from node A to node C, the impedance along the direct path line AC is half the impedance along the indirect path of lines AB and BC. Kirchhoff's laws dictate that power flows inversely proportional to impedance. Therefore, if A injects 1 MW, 2/3 MW flows across line AC, while 1/3 MW flows across lines AB and BC due to differences in impedance. Similarly, if B injects 1 MW, 2/3 MW flows across BC and 1/3 MW flows across BA and AC. On net, the flows are 1 MW across line AC, 0 MW across line AB, and 1 MW across line BC.

If each transmission line has unlimited capacity, various combinations of generation by generator A and generator B can satisfy demand at node C. But because lines have finite capacity, the feasible combinations of generation are restricted. Suppose demand at node C is 10 MW. Additionally, suppose that the capacity of the line between nodes A and C is 4 MW. This transmission capacity will restrict the feasible sets of generation because $(2G_A + 1G_B)/3 \le 4$. Generator A will be limited in its possible generation because feasible combinations of generation are only ones where demand equals supply ($G_A + G_B = 10$) and the transmission constraint is not violated ($[2G_A + 1G_B]/3 \le 4$). By solving the system of two equations and two unknowns, one can see that G_A cannot exceed 2, and G_B cannot be less than 8.

As a consequence, transmission constraints affect prices and the level of competition in auctions for power. Let both generators have enough generation capacity to supply the entire market (10 MW). Suppose generator A has a marginal cost of \$20 and generator B has a marginal cost of \$30. First, suppose that all transmission lines in the network have unlimited capacity. Assume the market is perfectly competitive, and both generators bid their marginal costs. Because it is the low bidder, generator A will produce all 10 MW, and the equilibrium price for power at node C is \$20. Note that if there were demand for power at nodes A or B, the delivered price also would be \$20.

Now assume the transmission capacity of line AC is 4 MW. Additionally, assume that both generators bid their marginal cost. The least-cost allocation of production that satisfies the transmission constraint is for generator A to produce 2 MW and generator B to produce 8 MW. Generator A would like to ship more across line AC, but the transmission capacity constraint generates scarcity rents. Generator A is willing to supply energy (at node A) for \$20, yet the capacity constraint implies that some of generator B's \$30 power must be purchased at node C. If line AC is congested, for one more MW to be delivered to node C, generator B must produce 2 more MW, and generator A must produce 1 less MW. Therefore, the price of power at node C is $2 \times \$30 - 1 \times \$20 = \$40$. However, the price is \$20 at node A and \$30 at node B. This form of pricing is called *nodal pricing* and leads to prices that vary by location when transmission constraints bind.

The story gets even more complicated if generators are not perfectly competitive and behave strategically. For example, generator B may recognize that its generation is necessary for load of 10 MW to be feasible and bid a price as high as is allowed. Thus, transmission constraints can create localized pockets of market power and, if generators own the transmission grid, will have no incentives to alleviate congestion.

This simple example illustrates several important points about the effect of the transmission grid or, more generally, the topology of the network on the operation of power markets. Power flows throughout the transmission grid rather than simply between two contracting parties. This is not the case for commodities that are transported by, say, trucks, where the transport of one firm's output often has no significant effect on the transport of another firm's output. The ability for a particular generator to send power through a transmission network is affected by both the amount of generation by other firms as well as by the capacity of transmission lines throughout the system. These bottlenecks affect the short-run efficiency of an auction market by creating local market power and impact the long-run incentives for investment.

Also, the amount of power that a generator can inject or a utility can withdraw at a given node varies over time in unpredictable ways if generators' outputs vary, plants suffer outages, or transmission lines are derated. As a result, prices at different locations are stochastic. The possibility that the price of electricity varies across location creates basis risk that parties on either the buy or sell side may wish to hedge against in a futures market. Hedging instruments need to be sufficiently sophisticated to allow for hedging at different locations on the transmission grid. One possibility is to establish tradeable property rights for use of the transmission grid. However, a system of transmission rights has complications. The definition of such rights is complicated because electricity flows according to Kirchhoff's laws (rather than how we tell it to). Also, if they are owned by a generating company that has local market power, the rights may exacerbate market power and create productive inefficiencies.[3]

The locational pricing of power and the design of transmission rights have important effects on investment in new generating plants. The technique of defining prices that vary by location in more complicated grid networks is both theoretically and practically challenging. If those prices are not defined in a way that provides the proper investment signals, the market may get new investment in the wrong locations while keeping old, inefficient plants that should be mothballed or abandoned. This lesson has been learned in several markets that have restructured. William Hogan discusses locational pricing and transmission rights in chapter 9.

Finally, the interaction between generation and transmission can hamper the ability of markets to yield the optimal level of investment. Generation and transmission assets can be both complements and substitutes. Additional transmission capacity can allow a generator to supply more power to the grid (e.g., in the preceding scenario, expanding the capacity of line AC allows generator A to produce more power). But additional transmission also can make a generator unnecessary if it allows power to be transported from a lower-cost generator. Generator A would have incentives to expand the transmission capacity if it owned the transmission network, but generator B would resist grid expansion if it owned the network. The externalities between generation and transmission are one reason that it is difficult for a market with vertically integrated firms in generation and transmission to align private and social incentives to invest optimally in new generation and transmission capacity.

Transaction Cost Considerations: The Case for Vertical Integration

The preceding discussion of how a market for power generation might function suggests that power-generating firms should operate independently of firms that own the transmission network. Otherwise, monopolistic abuses may arise with a vertically integrated firm having no incentive to eliminate transmission bottlenecks. But under regulation, virtually all power producers were vertically integrated. Was there a reason for this? Before embracing deregulation for generation and retailing and abandoning regulation with vertical integration, economists should not forget to ask whether transaction cost economics has anything to add to the dialogue.

The choice of deregulating electricity generation means that previously vertically integrated firms from generation through to local distribution will now be replaced by market transactions instead of intra-firm transfers. Transaction cost economics asks us to compare the efficiency of inter-firm transactions versus intrafirm transactions.

The writings of Oliver Williamson provide a clear framework for understanding how vertical integration among the three stages evolved.[4] In situations of long-lived, transaction-specific assets,[5] the market responds through long-term contracts or vertical integration to reduce transaction costs. Transaction-specific assets are those like a generation plant and an adjacent transmission line dedicated to moving the plant's output to the market. Both the plant and the transmission line are linked in a symbiotic relationship and would have little value without the other. Imagine separate owners of the generation plant and the transmission line. Both find themselves in a small numbers bargaining relationship and cannot simply walk away to another supplier. To avoid problems of hold up, they are likely to negotiate a long-term contract stipulating transmission charges, line flow rates, performance criteria, and other guarantees before embarking on such large investments. Obviously, if we assume costless enforcement, long-term contracts work fine as long as the two parties can enumerate the various situations they are likely to find themselves in and the obligations for each party. But as Williamson (1975) points out, economic agents have "bounded rationality," and contracts are not costless to enforce. In this situation, vertical integration may reduce transaction costs because within a firm, incentives are mutually aligned, and various sharing rules between the generation and transmission divisions can be resolved at lower costs.

Another feature of a vertically integrated firm is that it internalizes some of the externalities that would otherwise fall on third parties. To two parties engaged in a bilateral transaction, one party can take actions to avoid costs of $\$x$ on himself and in turn impose costs of $\$x + \$y$ on the second party. In effect, the first party imposes an externality on the second party. While long-term contracts in principle also can avoid inefficient outcomes, vertical integration seems ideally suited for internalizing certain types of externalities. As previously described, we see that capacity constraints on the transmission network can impose substantial external costs or benefits on generating plants located elsewhere on the system.

Given the extreme amount of long-lived, transaction-specific assets in the electric utility industry, it is not at all surprising that regulated firms evolved as vertically integrated firms. It evolved exactly as Williamson's theory would suggest. The question now is what effect will deregulation have if market transactions between generation and transmission replace intrafirm transactions? To economists who downplay the importance of transaction costs, their answer is "none"—market transactions will have the same or better efficiency characteristics than transactions under vertical integration. Still others may argue that vertical integration was critical for the industry in its formative years, but now as a mature industry, market transactions between the generation/transmission nexus may well be adequate given the large existing infrastructure. In contrast, a skeptic about the wisdom of deregulation might argue that vertical integration economizes on transaction costs, and deregulation faces two serious problems. First, if deregulation is coupled with vertical disintegration, significant transaction cost inefficiencies will be lost. Second, if deregulation proceeds with generation companies continuing to own transmission facilities, their regulated transmission business can enable their generation facilities to exercise market power in specific locations.

Ultimately, the performance of a deregulated, vertically disintegrated market structure versus a regulated, vertically integrated structure hinges on which institutional framework provides the best coordination features in assuring adequate expansion of generation capacity and the transmission network at the lowest cost. Both structures must solve the coordination problem of efficiently locating new generating plants and transmission lines. The solutions provided by the two structures are likely to differ in terms of the location of the capacity expansion and the amount of new capacity added. Proponents of deregulation point to the existing transmission network as a Balkanized system tied to the service areas of the incumbent companies. To them, deregulation is likely to result in a more interconnected transmission network. In contrast, the skeptic would argue that it is not clear that deregulation will result in sufficient vertical disintegration to avoid market power problems, and it is not clear that the coordination problem will be solved efficiently by markets.

Susceptibility to Huge Price Volatility and Market Power

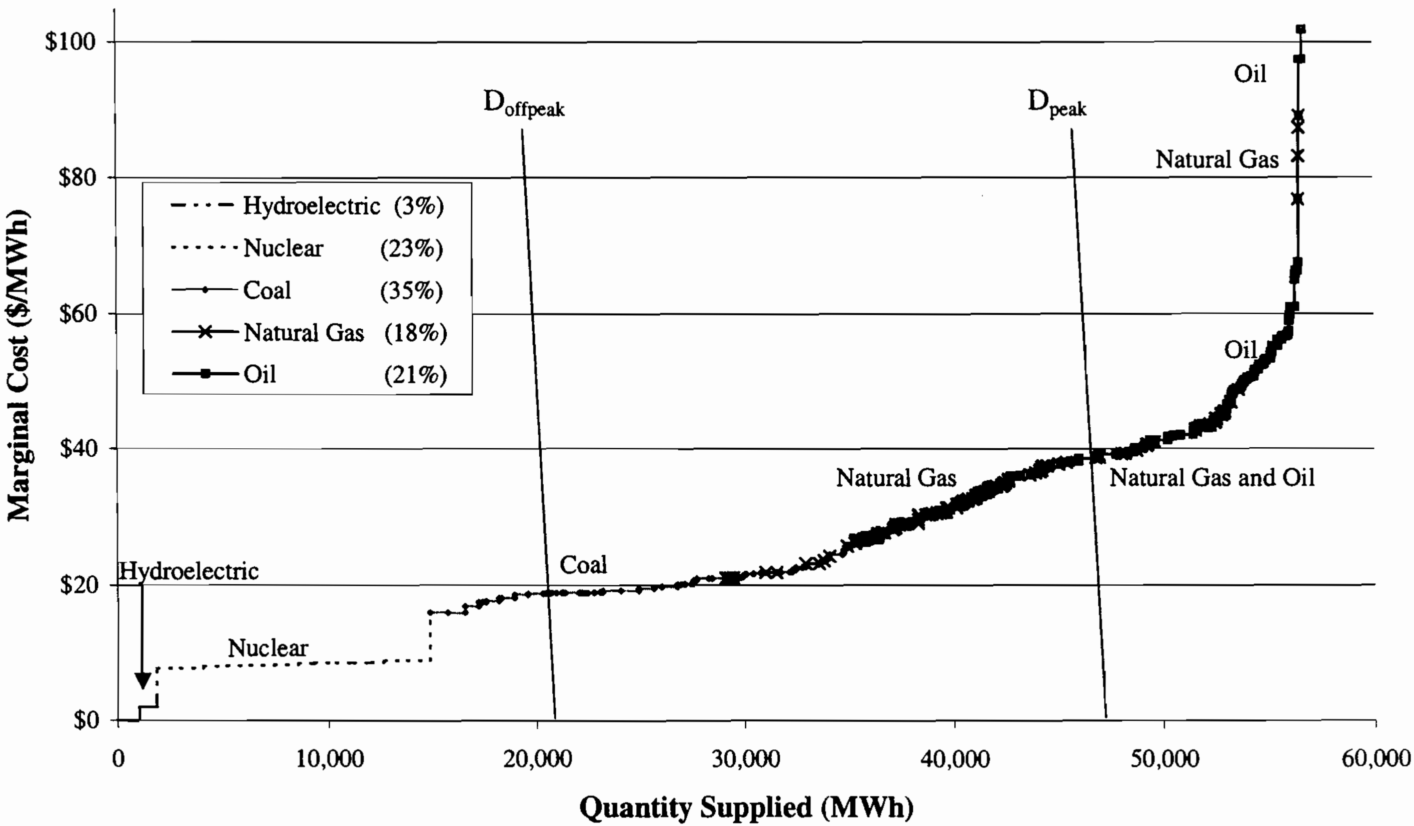
Price Volatility Is to Be Expected

Travelers to Europe are familiar with the high-season and low-season rates offered on hotels and airfares. Indeed seasonal variation in prices is quite common for commodities such as fruits and vegetables, gasoline, and heating oil. Price volatility in a deregulated electricity market (even a perfectly competitive one) will make the volatility in these other markets appear small by comparison. The explanation is simple. Demand during peak periods crosses the supply curve in the upward sloping section of the supply curve while off-peak demand crosses the supply curve in the highly elastic portion of the supply schedule, producing a much lower off-peak price. The extent of price variability depends on the following three factors: (1) the magnitude of the demand shift between peak and off-peak periods, (2) the price elasticity of demand, and (3) the elasticity of supply over the relevant range.

Figure 2 shows two demand schedules, a peak demand schedule and an off-peak demand schedule, and a single supply schedule for the Pennsylvania, New Jersey, and Maryland (PJM) market.[6] The supply schedule is the marginal cost of generating electricity from a variety of technologies. In a typical power system, these technologies may include generators fueled by nuclear, coal, natural gas, other petroleum products, hydroelectric, wind, and geothermal resources. The PJM system depicted in figure 2 shows the capacity of various generation technologies ranked from lowest marginal cost to highest. In PJM, there is a small amount of very low-cost hydroelectric capacity followed by nuclear and coal-fired capacity. The next units are efficient natural gas generators followed by less-efficient oil and gas peaking units. Each technology spins a turbine and generates mechanical energy by either burning a fuel that makes steam or a hot stream of gas or by using renewable resources such as falling water or wind. This mechanical energy is converted into electrical energy and injected into the transmission grid.

Figure 2 also depicts two hypothetical demand schedules. Both demand schedules are highly price inelastic because electricity does not have many short-run substitutes, and few consumers face the real-time wholesale price

Figure 2. Competitive supply and demand in Pennsylvania–New Jersey–Maryland (PJM)



Source: Mansur (2001) and PJM data.

anyway. The peak demand schedule, D_{peak}, reflects demand on a hot summer afternoon when demand intersects the competitive supply curve at a price of about \$40/MW. In contrast, the off-peak demand period, D_{offpeak}, reflects demand in the middle of the night. Off-peak demand intersects competitive supply at a price of about \$20/MW. The reader can easily verify that the price variability between the off-peak price and the peak price increases for (1) greater displacements between peak and off-peak demand and (2) the less price elastic (in absolute value) are the supply and demand curves. As shown in figure 2, price volatility increases dramatically when the peak demand schedule crosses the supply curve near the vertical section or perfectly inelastic portion of the supply curve.

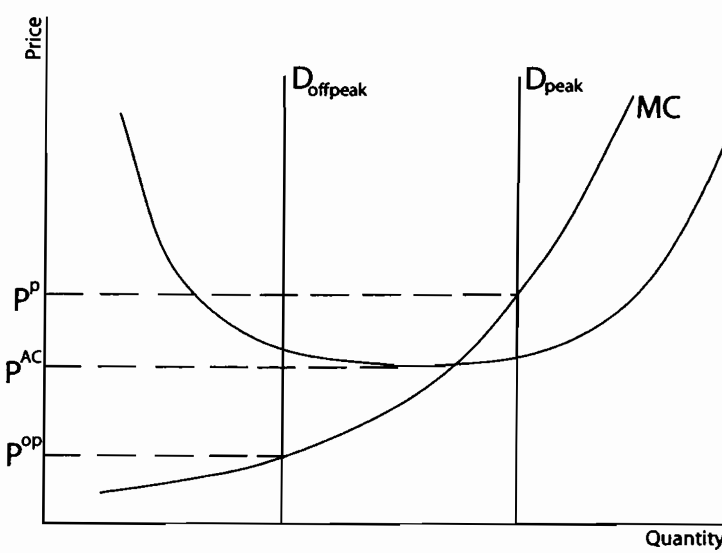
In a deregulated electricity market, the public should expect substantial price volatility because all of the conditions producing volatility are present in the case of electricity. First, peak and off-peak demand differ considerably. For example, in PJM in 2000, demand ranged from just above 18,000 MW to just below 50,000 MW. Air-conditioning in the summer and home electric heating in the winter produce a highly seasonal pattern of demand by residential and commercial users. Demand also follows distinct daily patterns. Because of the wide variability of demand, off-peak demand only requires the use of low-cost baseload supply. Off-peak customers operate in the highly price elastic range of the supply curve so that even if off-peak demand rises or falls by 10 percent, the effects on prices are minimal.

A second feature contributing to price volatility is the extremely price inelastic range of the supply curve during peak demand periods. At any point in time, the existing stock of generation equipment places a physical limitation on the ability to generate additional electricity. When demand approaches these constraints and it is necessary to start up high-cost generators, the resulting competitive price can be quite high. Prices must rise sufficiently high to compensate the less-efficient generators that only operate select hours of the year for their annual capital and maintenance costs. As noted earlier, a restructured market must provide the necessary capacity to meet these peaks in demand.

The third feature exacerbating the price volatility is the extreme short-run price inelasticity of demand. In the long run, when residential consumers have the ability to buy higher-efficiency appliances, the price elasticity of demand shows considerable responsiveness, ranging between 0.7 and 1.0.[7] But in the short run, it is a different story. In the short run, the stock of electricity-consuming equipment is fixed. The only question is what will be its usage rate, which in part depends on the price of electricity. Clearly, for many appliances, such as the microwave, electric oven, television, or computer, consumers are likely to be extremely price insensitive. For other uses, such as the thermostat setting on the air-conditioner or the time of day one operates the dishwasher, washing machine, or dryer, consumers can move demand out of the peak period into the off-peak period or perhaps choose to use less total electricity. Likewise, industrial users can move demand out of peak periods into off-peak periods by rescheduling downtimes and energy-intensive operations.

Yet another factor contributing to the extreme short-run price inelasticity of demand is that almost all retail consumers face a constant price of electricity that does not vary as cost varies. Under rate-of-return regulation, consumers pay the average cost of generation, which is typically flat over broad ranges of output. Indeed, regulators made little effort to distinguish between costs incurred during peak and off-peak periods. Figure 3 superimposes a hypothetical average cost curve on a marginal cost curve resembling the one in figure 2. Under rate of return regulation, consumers would pay a single price equal to average costs weighted over the year. Thus the price consumers pay, P_{AC}, which applies to both peak and off-peak periods, does not reflect the true social cost of power. There is no incentive to move consumption out of peak periods to off-peak periods and thereby conserve on peaking capacity. Many analysts advocate real-time pricing in which consumers pay prices tied to the hourly wholesale price. This would incentivize customers to move consumption out of peak to off-peak periods and thereby economize on system-wide capacity. Real-time pricing will send price signals that will evoke some price

Figure 3. Prices under average cost and marginal cost pricing

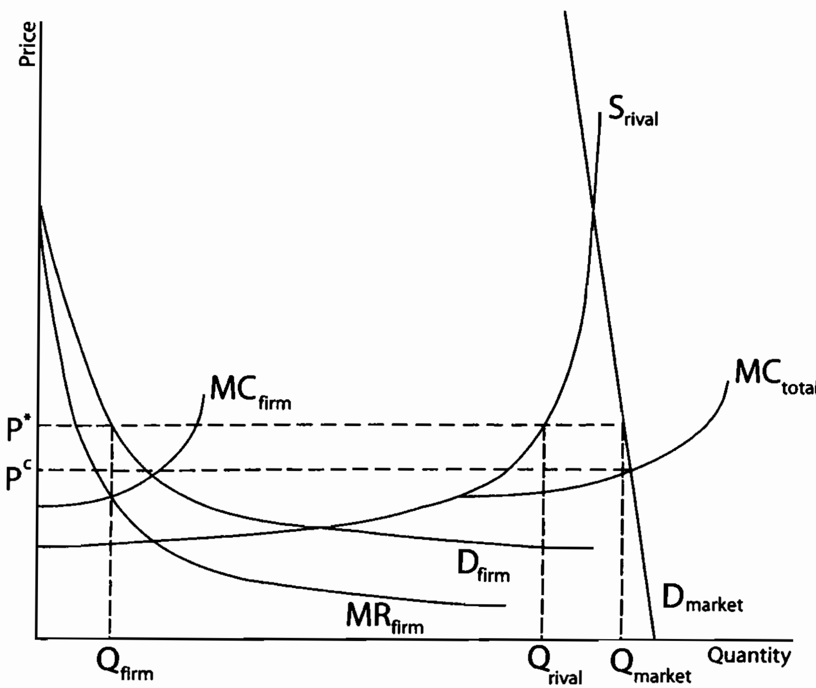


elasticity. Not all consumers will necessarily prefer real-time pricing because it is costly to monitor these prices and adjust consumption. For those who may benefit from real-time pricing, retail prices (on the margin) need to be as volatile as wholesale prices. However end-use customers can sign long-term contracts to hedge against variability in electricity bills, as Severin Borenstein explores in chapter 8.

Market Power and Price Volatility

The previous section explained that even in a perfectly competitive deregulated market, substantial wholesale price volatility is to be expected. Interestingly, these factors that naturally produce price volatility may also produce market power, which only exacerbates the price volatility. Market power is frequently measured by the ability to systematically charge a price in excess of the firm's marginal costs. Figure 4 illustrates how a generating company during peak demand periods is able to exercise market power. Total demand for electricity (D_{market}) is highly inelastic and would be perfectly inelastic if no consumers face the real-time wholesale price. Consider the decision of a par-

Figure 4. Exercising market power



ticular firm choosing how much to bid. Suppose for simplicity that all other firms are perfectly competitive and supply according to their aggregate marginal cost (S_{rival}). Then the firm faces a individual demand function (D_{firm}) given by the difference between the total demand, D_{market}, and supply by rivals, S_{rival}. Notice that rivals can supply the entire market but only if the price is very high. If the firm wants to maximize profits in that particular hour, it will choose the price corresponding to the quantity where its marginal revenue (MR_{firm}) equals its marginal cost (MC_{firm}). This leads to an equilibrium price (P^*) above marginal cost. The market is not economically efficient because the firm has some low-cost capacity that is not utilized while higher-cost capacity is being utilized by the rivals. Alternatively, if the firm had behaved competitively, its marginal cost curve would be added to rivals' supply function, giving a total supply curve MC_{total} and a competitive equilibrium price of P_c—well below P^*.

This example can be generalized to multiple firms exercising market power. Economists use the Lerner index (L) to measure the degree of market power.

$$(1) \quad L = \frac{(P - MC)}{P},$$

where P is price and MC refers to marginal costs. The Lerner index shows the markup above marginal costs measured relative to the good's price. The Lerner index has the nice property of equaling zero when price equals marginal costs—indicating the absence of market power. Indeed, a value of zero implies a perfectly competitive market. At the other extreme, a monopoly with the ability to set price far in excess of marginal costs will have a Lerner index closer to one.

If an individual firm maximizes profit as depicted in the preceding, it turns out that the Lerner index varies inversely with the elasticity of demand (ε_i) facing the firm i.

$$(2) \quad L_i = \frac{1}{\varepsilon_i}$$

In turn, the firm's price elasticity of demand, (ε_i), depends on the (absolute value of) market elasticity of demand, (ε_d), the elasticity of supply from other firms, (ε_s), the firm's market share, (S_i), and the market share of other firms, (S_o), as follows:

$$(3) \quad \varepsilon_i = \left(\frac{1}{S_i}\right)\varepsilon_d + \left(\frac{S_o}{S_i}\right)\varepsilon_s$$

Applying a little arithmetic to equation (3) and then plugging into the firm's elasticity of demand in equation (2) leads to some very interesting observations about market power. For example, let us consider the value of the Lerner index for a market with a dominant firm who has a 10 percent market share. Normally, one would not think of a market with the dominant firm possessing a 10 percent market share as being able to exercise significant market power. That is surely the case when one applies demand and supply elasticities relevant for many commodity markets. Suppose the market demand elasticity is 1 and the supply elasticity from the other firms to be 2, the dominant firm's elasticity is 28, which translates into a Lerner index of 0.036. A Lerner index of 0.036 is so small as to be almost negligible and indistinguishable from 0—the Lerner index of a perfectly competitive firm. If the dominant firm were to withhold 10 percent of its output (1 percent of market output), the market price would rise by 0.36 of 1 percent! Withholding such output would not be profitable because it would lose the profit on the last 10 percent of output while getting only a slightly higher price on the first 90 percent of its output.[8]

But now consider demand and supply elasticities relevant in electricity markets, especially during high-demand hours. Suppose the demand elasticity is 0.1, indicating a very inelastic market demand response to higher prices. Also, assume the dominant firm finds itself operating in the very inelastic range of the supply curve ($\varepsilon_s = 0.1$) as shown in figure 4 when firms are operating near the engineering capacity limits. Now suddenly, the dominant firm's elasticity of demand becomes 1.9 (in contrast to 28), and the Lerner index shoots up to 0.53. In this case, a firm with a market share of 10 percent can withhold 10 percent of its production (1 percent of total production) and raise the market price by 5.7 percent! Even though the firm loses the incremental profit on the last 10 percent of its output, it earns a 5.7 percent higher price on the first 90 percent of its output. In this situation, withholding output is likely to be a profitable strategy.[9]

The preceding calculation reveals a very important fact about figure 4 and electricity markets. When electricity firms face very inelastic market demand schedules and find themselves operating near engineering capacity as during peak demand periods, even firms with a 10 percent or smaller market share will have strong incentives to withhold production. During peak demand periods, the price spike that would occur under perfect competition will be exacerbated by firms unilaterally withholding capacity. This is a very surprising result because most market structures with firms controlling 10 percent or less of the market are considered workably competitive markets, and mergers involving such firms are routinely approved.[10]

Economists who design restructured electricity markets have offered several policy prescriptions to mitigate these incentives to exercise market power. Two of the most popular can easily be illustrated in this context. They are real-time pricing and long-term contracts. As explained in Severin Borenstein's chapter, real-time pricing requires some fraction of consumers to face the real-time wholesale price of power. When prices spike, consumers are aware of such increases in real time and can respond by decreasing consumption or shifting consumption to off-peak periods. Although real-time metering equipment is relatively rare in the United States, Borenstein's chapter shows that the costs of installing these meters is low compared to the potential benefits. Adopting real-time pricing would make the elasticity of market demand ε_d larger (in absolute value), which would reduce the firm's market power as measured by the Lerner index.

As discussed by James Bushnell in chapter 6, economists suggest that electricity generating firms be required to sign long-term contracts—selling a substantial fraction of their power at a predetermined price instead of selling it all in the spot market. Suppose that half of a firm's output is sold under long-term contracts and half is sold on the spot market. When a firm considers withholding 10 percent of its output to raise the spot price, it will only earn the higher price on 90 – 50 = 40 percent of its output rather than a full 90 percent of output. Substantial portions of production under long-term contract will dramatically reduce incentives to withhold.

One final issue that confronts regulatory agencies today is how to best respond to volatile prices. As one politician has noted, it is very difficult to sell electricity deregulation to constituents by offering to "subject voters to market prices." Highly volatile prices are likely to evoke a knee-jerk response by regulators to change market rules and reduce the volatility. Should market rules change dynamically as deregulation evolves? There exists a tradeoff in changing market rules. On one hand, there is much to be learned about the best way to design such markets and which rules are likely to make the market most competitive. This suggests that rules should evolve and regulators should have flexibility to adopt (presumably) better rules. On the other hand, uncertainty over the future rules of the game has its costs. Regulatory uncertainty can stymie investment, and better investment is the major theoretical upside of restructuring. Economists generally believe that uncertainty about the future competitive environment will dampen investment because choosing to make an investment is irreversible and forgoes the option value of making another decision later. However, the practical effect of regulatory uncertainty in electricity is not clear. One of the largest waves of new proposed powerplants occurred during the California crisis when prices were high but so was uncertainty about the future of restructuring.

There are a host of regulatory uncertainties that surround restructuring and affect investment. In the current context, a source of uncertainty that needs to be resolved is when prices should be allowed to go high. Consider two situations that could occur in a restructured market:

Situation 1: During periods when electricity demand is high and there are few additional supplies, generating firms exercise their potential for market power by bidding above the marginal cost of production.

Situation 2: Electricity demand is near the system capacity, yet firms utilize all available capacity at prices very close to marginal cost, and because expensive peaking units are called, the spot price is high.

These two situations call for very different regulatory responses. Regulators should mitigate attempts to exercise market power (situation 1) because it generates inefficiencies in production and leads to high prices for consumers. However, regulators should not interfere with the price-setting process in situation 2 because those prices signal scarce generation capacity and signal the value of new investment. Unfortunately, these two situations may be observationally equivalent to the regulator. The regulator sees high load and high prices but does not have sufficiently detailed information to determine if the prices reflect market power or true scarcity. And even if economic analysis can separate between the two situations, politics may not.

This complicated problem combined with the fact that the regulator may have no ability to commit to a set of rules for the foreseeable future generates a great deal of uncertainty to potential investors. Such regulatory uncertainty is one argument in favor of adopting a competition policy that mitigates market power by regulating the structure of the market (through divestiture or mandatory forward contracts) rather than regulating individual bidding behavior or instituting "good behavior" clauses.

The Political Economy of Electricity Deregulation

You are soon to embark on a tour through the various landscapes of electricity deregulation, but before doing so, it is important to remember that policy decisions may occur in a technical vacuum, yes, and even in an economic vacuum. But never do they occur in a political vacuum. The fact that the restructuring of electricity markets has been characterized as *deregulation* is in fact a misnomer. Because in recent years the word *regulation* conjures up many images of wasteful bureaucracies standing in the way of innovation, it is not surprising that proponents of restructuring electricity markets call it *deregu-*

lation. After you have finished the guided tour of this volume, it will be clear that as the restructured electricity industry makes greater use of markets, regulatory oversight will continue even for the deregulated generation and retail sectors. Transmission and local distribution will remain heavily regulated.

In assessing the success of electricity restructuring, the metric with which it is compared to matters greatly. Compared either to a model of perfectly competitive markets or to the model of omniscient regulators overseeing the market, it is clear that all examples of restructuring will fail. But this is the wrong comparison. The relevant comparison is the previous world left behind. But the world left behind is very different in Europe and Latin America than the various states within the United States. In the United Kingdom, as Richard Green's chapter explains, electricity generation was formerly a state-owned enterprise. In the United Kingdom, electricity deregulation was a transition from a public enterprise to private firms subject to loose regulation of prices. In contrast, electricity deregulation in the United States has not involved privatization but instead has involved releasing privately owned electricity generators from rate-of-return regulation and allowing them to earn market-based rates. To the extent that public enterprises were less efficient than their privately owned but regulated U.S. counterparts, the benefits of deregulation are likely to be much greater in Europe and Latin America than in the United States.

Another advantage to deregulation in Europe and Latin America is that by eliminating the public enterprises, policymakers are able to wipe the blackboard clean (or at least cleaner than in the United States). Public enterprises can be privatized and divided into pieces suitable for the promotion of competition. In the United States, the restructuring of the industry must work within the constraints of the existing private ownership of generation, transmission, and distribution assets. A classic example of vestiges from the past constraining the choices for deregulation in the United States arise from "stranded costs." Stranded costs are the costs of past investments in generation or contracts to buy power at high prices. For example, in the 1970s a number of utilities invested in nuclear plants with large cost overruns. These costs were primarily fixed costs that were embedded in regulated electricity rates that ended up being much higher than wholesale prices prevailing in the late 1990s. Because these investments were made in a regulated environment that assured investors a fair return on capital, these utilities demanded recovery of stranded costs as a condition for their acceptance of deregulation. In contrast, the legacy of past regulation was not as complicated in the United Kingdom—electricity assets were publicly owned and could be sold to private firms. But in the United States, the price of political support of the incumbent regulated utilities for deregulation depended critically on whether they could recover these stranded costs in future fees.

If the blackboard is already looking muddled for the U.S. deregulation experiment, we have yet another factor to add—consumer benefits. To rally consumer support for deregulation, there must be *immediate* evidence of consumer benefits in the form of lower prices. Obviously, policymakers have a problem. Utilities want recovery of stranded costs, which necessarily raises retail prices. Yet consumers want lower prices. Indeed, if utilities were not able to recover stranded costs, there would be a deregulation dividend for consumers. The problem becomes how to wring enough short-run efficiency gains out of a deregulated generation sector to pay stranded costs and at the same time provide consumers with rate reductions. This is a tall order, especially because any big cost savings are likely to be realized in the long run. In the long run, firms will invest in lower-cost generation technology and adopt lower-cost operating procedures, as Catherine Wolfram discusses in chapter 5. Also, if real-time pricing is implemented, demand can be shifted out of the peak periods and very high-cost peaking capacity can be reduced, enabling a much more efficient generation sector. But changes like this will take time, and consumer support for deregulation depends on immediate benefits.

Finally, U.S. restructuring is complicated by overlapping regulatory jurisdictions. Regulatory control is divided (sometimes not clearly) between federal, state, and local authorities, which can impair the coordination of markets and lead to power struggles. Two examples are noteworthy. Part of the blame for the California crisis can be attributed to the passing of the hot potato back and forth between the state of California and the Federal Energy Regulatory Commission (FERC). Frank Wolak discusses this example of regulatory failure in his chapter on the California crisis. As another example of divided authority, the pricing of power in wholesale markets lies largely in the purview of FERC, while retail pricing is governed by state public utility commissions. This can lead to problematic disconnects between the price signals sent by wholesale and retail markets. Interestingly, Texas does not have divided state and federal authority because the grid is not interconnected with the rest of the U.S. grid. It remains to be seen if Texas will overcome the potholes on the restructuring path more effectively than states with divided jurisdiction.

In sum, the political economy of electricity deregulation is far more complicated in the United States than elsewhere for a variety of reasons. First, unlike Europe's experience with public enterprises, it is less clear that the regulated, privately owned utilities in the United States were in need of fixing. Second, deregulation in the United States was constrained by existing patterns of vertical integration between distribution, transmission, and generation. The vestiges of that system cannot be erased. Third, both to avoid lawsuits and garner support for deregulation among incumbent utilities, stranded-cost recovery had to be an important component of any deregulation plan. Fourth, policymakers face the difficulty of producing immediate consumer benefits to obtain public support for deregulation and still paying the stranded-cost dividend to incumbent utilities. Paradoxically, to the extent that there are substantial benefits to consumers, these gains are likely to be realized in the long run. While the political economy of electricity deregulation is another whole monograph in itself, the reader can look forward to Paul Joskow's chapter, which enumerates many of these issues.

Outline of this Volume

In chapter 1, Paul Joskow highlights the critical policy questions in electricity deregulation. As discussed previously, electricity deregulation is not a hands-off process—it requires a substantial amount of design and regulatory oversight. There are many potential potholes on the road to an efficient deregulated market. Joskow provides a roadmap to the biggest challenges in transitioning from cost-of-service regulation to competition. Joskow, an economist at the Massachusetts Institute of Technology (MIT) and one of the most respected and prolific analysts of electricity markets, draws upon his many years of research experience in both the regulation and deregulation of the electricity industry. He reflects upon existing deregulation experiences to identify lessons learned about the performance of restructured electricity markets.

The next three chapters present case studies of specific markets that have been deregulated and discuss lessons that can be learned from those experiences. In chapter 2, Richard Green, a professor of economics at the University of Hull in England, analyzes the first major market to deregulate—England and Wales—which began restructuring in 1990. By perhaps the most important standard, U.K. electricity deregulation has enjoyed considerable success. The ultimate goal is to reduce prices, and U.K. prices have fallen substantially since initial deregulation in 1990. However, the market also has experienced some problems, including the exercise of market power. Green discusses how the England and Wales regulators anticipated and reacted to these problems, and he draws upon more than a decade of restructuring experience to illustrate lessons for other markets.

In chapter 3, Frank Wolak discusses the ill-fated California market. Policy analysts have widely divergent views on what caused the California market to collapse in 2000–2001. Most agree that the California crisis was some combination of rising input costs, poor market design and the exercise of market power, and failed market oversight by state and federal regulators. However, analysts differ on the weights to attach to each contributing factor. Wolak discusses each of these factors and argues that the California crisis was caused primarily by regulatory failure. Wolak, an economist at Stanford, is uniquely qualified to analyze the California market because he has served on the Market Surveillance Committee of the California Independent System Operator.

The final case study is the Texas market, which opened as a single market in 2001. Similar to England and Wales after reform, the Electric Reliability Council of Texas (ERCOT) is a "bilateral" market. Rather than serving as a market maker, the system operator takes the more passive role of collecting schedules of bilateral trades and only running a small residual market for balancing supply and demand in real-time. Texas has made other design choices that differ from other markets. For example, Texas developed policies to encourage new investment such as reducing the costs of connecting to the grid, but ERCOT has no market for installed capacity. Also, ERCOT allows generators to choose how to dispatch their generating units rather than dispatching units with an optimization algorithm run by the system operator. Ross Baldick and Hui Niu, electrical engineers at the University of Texas, take us on a tour of ERCOT's market design choices in chapter 4.

The second part of this volume discusses specific policies for the successful design of wholesale and retail markets. One of the themes that will recur is that electricity markets must be carefully designed to ensure that incentives are properly aligned and they operate efficiently. Otherwise, much can go wrong. These potential problems have led some policymakers and analysts to question whether we should go down the road of electricity deregulation. However, the focus on how to (and how not to) design such markets should not be taken as a prescription to halt deregulation. One of the difficulties in "selling deregulation" is the timing of the costs and benefits. The costs are likely to be front loaded, while the benefits are back loaded. Many of the costs are likely to come in the form of market design flaws as the industry transitions from costs-of-service regulation to competition. However, the benefits are likely to accrue in the medium and long run as generators find ways to shave off operating costs and invest in new generation technology. In chapter 5, Catherine Wolfram discusses the various channels through which deregulation can reduce costs of procuring electricity. Because many of the benefits will not show up in the short run, it is premature to make an overall assessment of the efficiency improvements. Wolfram provides some early estimates of cost reduction and lays out methodologies and data that can be used in the future to measure the benefits of deregulation.

After foreshadowing the current and predicted future benefits of deregulation, we turn to the downside risks. One of the biggest risks is that the markets will not be sufficiently competitive and electricity generators will be able to exercise market power. In chapter 6, James Bushnell evaluates tools to screen the potential competitiveness of restructured electricity markets. He reviews the screens that historically have been favored by U.S. antitrust authorities and the FERC. It turns out that these screens can fail spectacularly when applied to electricity markets. Bushnell illustrates techniques to detect potential market power that are better suited to electricity. These techniques draw upon oligopoly models in the economics literature to simulate what prices would be under various structural arrangements. Essentially, Bushnell assumes firms choose each period to produce the quantity that maximizes their individual profit taking their rivals' production as fixed (i.e., Cournot bidding). He simulates what prices would be under the ownership structure in California and finds that the simulated prices fit the data quite well.[11] This suggests it is reasonable to estimate what prices would be under various alternative ownership structures and use those simulations in deciding on whether divestiture is required or long-term contracts should be mandated. Bushnell's paper simulates other possible counterfactual ownership structures and find that real-time pricing and reduced supplier concentration could have significantly reduced prices during the 2000 California electricity crisis. These techniques are useful screens that can be employed in other markets to determine ownership structures and contracts that will make prices competitive.

Market power mitigation can take several forms. While Bushnell describes the importance of market structure for obtaining competitive prices, Alvin Klevorick discusses the need for continual regulatory oversight of bidding. Klevorick, who teaches both law and economics at Yale, brings years of experience in regulatory oversight to market power concerns in electricity. In chapter 7, Klevorick explains why deregulated electricity markets must be constantly monitored to ensure they are competitive. He offers guidance on how market monitoring should be conducted at both the federal and local level. In addition, he compares the relative merits of different approaches to regulate prices including price caps and bid-adjustment procedures.

In chapter 8, Severin Borenstein discusses how electricity should be priced to retail consumers. Economic theory suggests that forcing consumers to face the real-time price of energy can reduce the amount of needed generating capacity as well as reduce prices and the overall cost of electricity. Despite the strong theoretical justifications for real-time pricing, few utilities in the United States have experimented with such programs. Two of the biggest obstacles to implementing real-time pricing are the costs of installing real-time metering equipment and the reluctance of customers (and their legislators) to face price risk. Borenstein argues that these obstacles are not difficult to overcome. Installing real-time meters for large customers easily passes the benefit-cost test. Also, cleverly designed pricing programs can protect consumers from substantial bill volatility yet still provide the proper price signals. Borenstein describes a variety of real-time pricing policies that yield the frequently cited benefits of demand response yet overcome some of the most common complaints of real-time pricing.

In chapter 9, William Hogan, professor of public policy and administration at the Kennedy School and research director of the Harvard Electricity Policy Group, discusses how use of the transmission grid should be priced to make the electricity market efficient. Ideally, prices should send signals about the optimal location of new generation and transmission investment on the grid. One means to ensure these signals exist is for wholesale electricity to have different prices at different points on the transmission grid reflecting scarcity of transmission capacity. But this leaves open the question of who will listen or who should listen to those price signals. Some analysts claim that "regulators" should decide on new transmission investments while others believe that new transmission investment should be left to merchant firms. Hogan analyzes these issues.

In chapter 10, Shmuel Oren, professor of industrial engineering and operations research at University of California, Berkeley, discusses how markets should be designed to ensure that adequate generation capacity is available to meet demand. Under the rate-of-return regulatory regime, utility planners in various agencies in conjunction with investor-owned utilities made investment decisions to ensure adequate generation capacity. In restructured markets, this planning process is "left to the market." It is possible that perfectly competitive markets for electricity will create the proper long-run incentives for investment. According to the theory, firms bid their marginal cost and earn scarcity rents during periods of high demand. Those scarcity rents exactly cover the capacity costs of generating units in long-run equilibrium. But this theory has complications in practice. In fact, Paul Joskow's chapter finds evidence of insufficient investment incentives from the energy-only market in New England. Some analysts recommend additional "capacity markets" where generators are paid for being available to generate, independent on the actual amount of energy generated. Oren discusses how such markets can be designed.

Finally, we want to ensure that our discussion does not occur in a political vacuum. So in chapter 11, we complement the academic analyses with perspectives from policymakers and stakeholders. The first perspective is from Pat Wood III, who is Chairman of the federal agency that regulates wholesale electricity markets—the FERC. Wood argues that electricity markets require certain structural elements to ensure they are efficient and function properly. Otherwise, these markets can fall victim to a variety of the textbook "market failures" of economics. He highlights eight elements of the FERC policy that should serve as core features of regulatory policy. Thomas R. Kuhn, president of Edison Electric Institute, offers his opinions on the best legislative and regulatory rule changes to ensure the continued growth of the electricity industry. In conclusion, U.S. Congressman Joe Barton, chairman of the House Subcommittee on Energy and Air Quality of the House Committee on Energy and Commerce, discusses his vision of future legislation to continue to push forward with competitive markets rather than return to regulated rates.

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Notes

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1. For a detailed discussion of the evolution of electricity restructuring, see Joskow (2000).

2. See Bergen and Vittal (2000) for a full description of power flows in various networks.

3. See Joskow and Tirole (2000).

4. See Williamson (1975) for a general discussion or Joskow (2002) for one specific to electricity.

5. Transaction-specific assets occur where the producer and buyer are tied together without easy access to alternative sources of demand and supply.

6. We thank Erin Mansur for providing us with the data underlying this graph. Further details of the PJM market can be found in Mansur (2001).

7. See Taylor (1975) as an example.

8. As long as the marginal cost was 3.3 percent or less below the initial price, it would not be profitable to withhold output.

9. In this case, withholding of output will always be profitable as long as marginal costs are 51 percent or less of the initial market price.

10. For a good analysis of the shortcomings of using concentration measures for inferring the competitiveness of electricity markets, see Borenstein, Bushnell, and Knittel (1999).

11. Puller (2004) uses another methodology and finds that producer behavior is fairly consistent with unilateral profit maximization.