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# Regulatory Reform in the Electric Power Industry

Vernon L. Smith

Economists have traditionally argued that the production and distribution of electric power—along with telephone, water, and natural gas services—were natural monopolies: economies of scale implied that the natural economic result was for only one company to emerge and for monopoly prices to prevail. Consequently, efficiency and fairness required that such industries must either be owned and operated by the government or regulated by it. In Arizona, for example, monopoly was such a concern to the framers of the state constitution that they explicitly affirmed that “monopolies and trusts shall never be allowed in this state.” An early position taken by the Arizona Corporation Commission applied this concept to electric power: “We believe that ordinarily the distribution of electric energy is essentially and rightly monopolistic in its application.”

This view has served to rationalize a political equilibrium in this country in which most electric utilities are privately owned, but subject to price controls based upon “fair” rate of return regulation. In many foreign countries, including the United Kingdom, New Zealand, Chile, and

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several other South American nations, the electric power industry has until recently been owned and operated by central governments. However, the traditional argument for natural monopoly is buckling under the forces of change, and its proponents are now on the defensive.

The convergence of a number of intellectual, political, and economic developments, beginning in the late 1970s and continuing through the 1980s, has inspired many analysts to radically reevaluate the traditional view of natural monopoly. These recent developments include: (1) revisionist views on the origin of state utility regulation; (2) theoretical and empirical challenges to the natural monopoly view of the electric power industry; (3) incentive problems under rate of return regulation; and (4) the worldwide economic failure of government utility ownership and regulation, which weakened political opposition to reform.

## Revisionist Views of the Origins of State Utility Regulation

The folklore that the original purpose of regulation was to protect consumers from monopoly prices is now being challenged. From 1879 to 1907 electric utilities were not subjected to any price regulation. They were required to obtain

operating franchises from municipalities, but the literature of the day described an era of free competition in which municipalities granted franchises to many who applied. It was the industry itself, whose profits suffered from open entry, that vigorously lobbied for entry restrictions and for state regulation of prices and profits. Beginning in 1897, Samuel Insull, then president of the industry's National Electric Light Association and a persistent advocate of regulation, repeatedly called for exclusive licensing of electric utilities and for "fair profit" price control by state governments. The resulting regulations served to protect the industry from the competitive pricing that dominated its early history. Theodore Vail's influence on the early regulation of the telephone industry was strikingly parallel to that of Insull in electric power.

A study of the period 1900-20 shows that the first states to adopt regulation were those in which electric rates and profits were lowest and output highest. Furthermore, the effect of regulation during the early period was to increase prices and profits and to reduce output. These data support the hypothesis that regulation was a response to the utilities' desire to protect profits, not a consumerist response to monopoly pricing. Indeed, monopoly pricing had not been a significant problem.

### Challenges to the Natural Monopoly View

The idea that the electric power industry is inherently a natural monopoly stems from three arguments: (1) that there are economies of scale in the production and delivery of electricity; (2) that duplication of facilities is inefficient; and (3) that natural monopoly cannot be disciplined by entry or the threat of entry.

**Economies of Scale.** The theory, that economies of scale in production implies that a single firm can serve the market at lower cost than multiple competitors, is essentially a classroom exercise in static economic analysis. It assumes that demand is constant and that supply is certain. In reality, the industry is subject to highly variable daily, seasonal, and geographical fluctuations in demand, as well as growing annual average demand, and to potential power-supply interruptions due to technical problems. A firm would have to build multiple parallel generation and transmission facilities to assure an uninterrupted supply and to meet peak load demands, even if there were

unbounded economies of scale in building these units.

Furthermore, growing demand, together with the durability and irreversibility of large capital investments, makes it economical to add capacity in discrete, parallel lumps that are smaller than if one had no capacity available at the time of increased demand. Thus, a transmission line large enough to meet all future demand would be subject to a long period of idle capacity cost, to say nothing of obsolescence cost. Consequently, one builds capacity to meet some anticipated growth, then adds parallel capacity later. These economic and technological considerations have led to the extensive use of multiple facilities, in both generation and transmission, by individual firms. Arizona is a representative case: a handful of companies own more than 30 producing plants, many with multiple turbines and several parallel transmission lines.

**Duplication.** Local distribution systems are often thought to present the strongest argument for natural monopoly: to avoid inefficient duplication. It is significant that in the 1915 report of the Arizona Corporation Commission, quoted above, it was the distribution of electricity that was singled out as "essentially and rightly monopolistic."

One flaw in this view is that, in other industries, such "duplication" is the norm and widely applauded as providing diversity of service. For example, innumerable neighborhoods are served by multiple supermarkets and service stations, sometimes located next to each other, and shopping malls normally have competing stores selling the same product. Contrary to the conventional view, New Zealand (see below) has eliminated the monopoly franchising of local distribution.

Many early empirical studies challenged the traditional claim that relatively large firms can capture economies of scale and produce at lower unit cost. For example, Professor Marc Nerlove, who has studied returns to scale in electricity supply, found only modestly decreasing average unit costs in medium-sized firms and increasing average unit costs in larger firms. Nor is there evidence that integrated gas-electric utilities achieve lower unit costs by, for example, capturing scale economies in meter reading or billing. Studies comparing cities with and without combined gas-electric utilities consistently show that combined utilities have higher, not lower, electricity rates. Electricity and gas compete as alternative forms of energy, and this competition tends to discipline prices and

costs even within the regulatory apparatus.

A complication of the view that distribution utilities are natural monopolies is that it is often accompanied by the assumption that providing distribution necessitates investment in generation. But where transmission is adequate, there is no technological or economic reason why a distribution utility cannot acquire all its power by contracting with competing generators. For example, in Arizona, city-owned Mesa Electric has in the past met all its energy needs by contracting. Distribution utilities need not produce their own power, any more than they need to produce their own trucks.

**Threat of Entry.** In Arizona and other states, ownership of electric facilities is concentrated in a few firms. This is the direct result of exclusive franchising, not of natural monopoly. Indeed, the most serious indictment of natural monopoly as a justification for regulation is the widespread granting of exclusive monopoly franchises. In Arizona this has been the effect of the Arizona Supreme Court's decision in *Trico v. Tucson Gas* (1969), that duplication of services is prohibited under a certificate of convenience and necessity granted by the state. If anything is clear and unambiguous in the theory of natural monopoly, it is that such monopolies are "natural." By definition, legal restrictions on entry are therefore superfluous. Exclusive franchising appears to be a legacy of the industry's early opposition to competitive entry, not the result of academic natural monopoly arguments.

Exclusive franchising removes the threat of entry. This is an important consideration that was not recognized in the theory of natural monopoly. If entry is legally unimpeded, the incumbent firm must recognize that monopoly prices may attract an entrant that can compete with the incumbent firm. The merely theoretical competing plant that has not been built, but could be (and could perhaps produce at lower cost due to technological improvements), can itself deter monopoly pricing. This theory, known as "contestable markets theory," has been developed at length, and found to have empirical support.

### **Incentive Problems under Rate of Return Regulation**

After the period of rising prices following the introduction of state regulation, the electric

power industry and its customers benefited from falling inflation-adjusted electric rates for almost half a century, from the 1920s until about 1970, excluding the rapid deflationary years of 1930-33. The long decline in rates was due largely to the falling real price of petroleum and to improved technology that increased the thermal efficiency of fossil-fuel steam generation.

The new technology provided an efficient means of capturing the engineering economies of scale of large generation and transmission facilities. Such scale economies are always theoretically available based on engineering principles. The problem is to find ways of building the larger units so that the resulting decline in fuel requirements per unit of output is not more than

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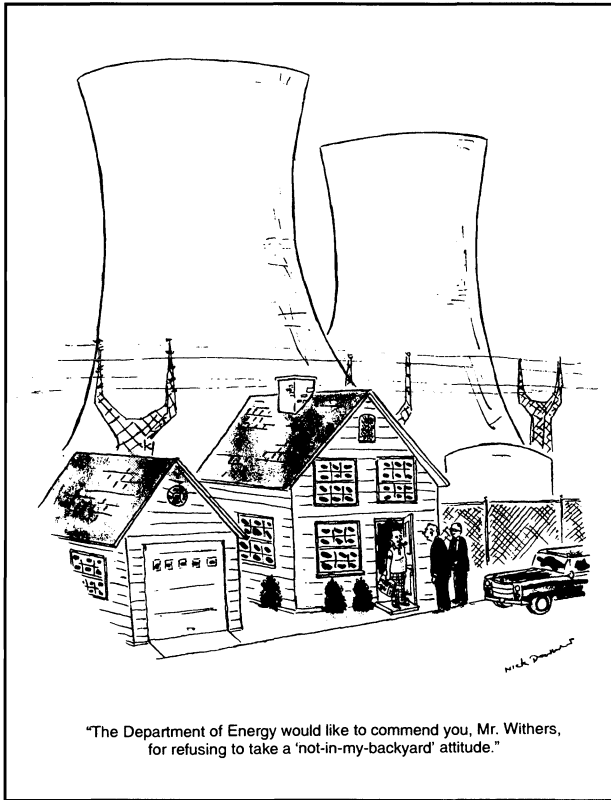
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offset by increased capital costs per unit of installed capacity. The efficient capacity of a generator or transmission line is always limited by the current state of technological knowledge, including construction know-how; beyond this limit, increases in capital cost per unit of capacity restrict the economical size of the plant. Growth in demand allows these new technologies to be introduced painlessly—expansions in capacity are needed to meet demand, so companies install the most advanced, lowest-cost technology to meet the increase in demand.

These external developments, however, mask the internal incentive problems of cost-plus pricing under rate of return regulation. Such prices are based on historical cost, not the costs of current technology. In unregulated industries subject to rapid technological advances, competition forces the obsolescence of facilities before their historical cost is fully "depreciated." Efficiency requires that obsolete facilities be abandoned earlier in accordance with their shortened economic lives. Under rate of return regulation, such assets tend to be protected by averaging their historical cost, along with the lower cost of new facilities, into the rate structure.



Consequently, price declines in electric power were actually retarded by rate of return regulation, especially in the period of rapid general price deflation, 1930-33. Since rates were generally falling, there was no political motivation to question the efficiency of the regulatory apparatus.

Beginning around 1970, the industry's tranquil half-century of hidden problems ended abruptly. Improvements in fossil fuel technology slowed considerably. The political environment suddenly demanded more severe pollution standards. Petroleum prices began their unprecedented increase, rising from \$3 per barrel to \$12, and ultimately to over \$40. Accelerating inflation also drove up nonenergy input prices and construction costs. Whereas earlier regulatory lag in approving cost-based rate increases had benefited profits, it now squeezed profits severely.

In response to this new environment and to anticipated demand growth, much of the industry turned to nuclear construction, although the availability of low-sulphur coal continued to attract new plant investment in the Southwest. At the time, nuclear power, with its promise of scale economies and much lower fuel costs, seemed to be the answer to the industry's

wrenching problems. Moreover, the regulatory environment had long promised rates that would yield the revenues required to cover costs, plus a reasonable profit. Only utility industry managers routinely use the phrase "revenue requirements": investment costs, once incurred, lead to revenue requirements that consumers should be expected to pay. This was not an environment that would condition managers to be wary of untried technologies or of possible cost overruns. With this history, it was reasonable for managers to expect that construction costs would be embedded in new, higher rates if such were required.

Decisions in the 1970s to pursue relatively untested nuclear technologies in an inflationary economy led to the cost overruns of the 1980s. The prime example in Arizona was the Palo Verde nuclear facility, although its cost overrun was less severe than those in some other parts of the country. Many of these cost overruns were more than the political environment could absorb.

Although rates generally were increased—at times substantially—the commissions balked at fulfilling management expectations that new rates would cover the full revenue requirements of these costly ventures. That some utilities and some states relied on alternatives to nuclear construction exacerbated the problem. In the Southwest, some utilities expanded with traditional coal-fired technologies. Wisconsin used load-shifting programs and time-of-use rates to encourage conservation as a substitute for expanding capacity. Consequently, with 20/20 hindsight, some managers and commissions clearly had controlled costs better than others. Politically, this increased the difficulty of rewarding the costly nuclear plants with cost-plus rate schedules.

Widespread fears that the energy crunch was here to stay, and that power shortages existed, caused many to believe that new political initiatives were required. One response was the Public Utility Regulatory Policies Act (PURPA), adopted in 1978, which provided tax benefits to encourage tiny "mom and pop" hydroelectric, windmill, solar, or woodchip-burning power sources. PURPA also required utilities to purchase both this power and power from industrial cogeneration units at rates as high as avoidable cost: the most expensive source of marginal power available to the utility. The positive side of PURPA is that it helped utilities to overcome their reluc-

tance to deal with alternative energy sources. Many cogeneration projects are competitive at today's power rates even without special inducements. PURPA also demonstrated that decentralized power generation can be compatible with long-distance transmission. On the negative side, some states applied the avoided-cost concept in a way that encouraged an oversupply of uneconomical energy.

The Northeast experienced a surplus of power produced under contracts between utilities and independent power companies. Part of New York's surplus was the result of a state law (repealed in 1992) requiring utilities to pay a minimum of 6¢ per kilowatt hour for power from independent producers. While such incentives are, of course, quite effective, they can hardly be justified as benefiting consumers. With the wholesale spot price recently 2¢ per kilowatt hour (a price level caused by the proliferation of these contracts), contracts at 6¢ were not viable. Many have been renegotiated in the venerable market tradition that long-term contracts stand only so long as short-run prices do not fall persistently below the contract prices.

All markets are "regulated" in the sense that participants are constrained by private and public rules governing (property) rights to act. The problem that must be avoided is using failures in the regulatory process itself to justify continued and more invasive regulation. Such failures are inherent in the regulatory process because the announced intentions of regulation—such as limiting profit to a "fair" return on the "prudent" use of capital—create incentives that are incompatible with the intentions. Firms, seeing rate of return regulation as guaranteeing a markup over cost, are less motivated to control costs than they would be in competitive regimes where a residual claimant gets to keep whatever is saved. Prices under rate of return regulation are set by adding capital cost and a profit rate to other costs, thereby attempting to reverse the competitive process by which prices determine the amount of capital cost one can profitably afford to incur.

In other countries, government-owned industries suffer from similar incentive problems. Numerous foreign governments have embarked upon restructuring and privatization programs for their electric power industries in an effort to find a property rights approach that avoids these incentive problems.

The United Kingdom launched a denationalized competitive structure for electric power in early 1991 when the Crown's nonnuclear generation capacity was sold to private companies. But Britain was not the first; Chile privatized its industry, creating a competitive market for generation, a decade ago. Argentina has been in the process of privatization along British lines, and New Zealand is in the process of defining how to

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restructure the industry to make it competitive and minimize the need for regulation. Australia is working on proposals for creating a market on its Eastern and Southern grids. Since all these examples share characteristics with the "British experiment," this article will discuss that case in detail, and follow with a discussion of New Zealand's approach.

**Privatization in the United Kingdom**

The two principles that survived the political process in Britain were, first, that efficiency is the primary objective, and, second, that competition is the vehicle for accomplishing that objective. Of course, all regulatory systems, including both state-owned and rate of return systems in the United States, proclaim efficiency as an objective, but the administrative processes for achieving it have been notoriously unsuccessful. Under the United Kingdom's new approach, competition is intended to be the primary means for disciplining costs, prices, and service, but it is overlaid with central dispatch to maintain coordination and reliability. The U.K. approach also involves some regulation, but it is intended to be relatively light-handed compared to rate of return regulation, and is intended to minimize adverse incentives.

**Obligation to Serve.** There is no obligation to supply on the part of any entity producing power, or providing distribution or transmission services. The absence of an obligation to supply is not as radical a departure from U.S. regulation as might be thought. Despite much rhetoric in

the United States claiming that the "regulatory compact" obliges utilities to serve everyone in their area, one has only to refuse to pay one's utility bill to find out how long the obligation to serve will keep the lights burning. The practical impact of the obligation to serve is price discrimination. Since there are limitations on refusing service to higher-cost customers, others must pay higher rates to maintain the utility's allowed rate of return. Price discrimination occurs wherever the price charged, whether too much or too little, is not justified by the assignable costs incurred. Different prices are not discriminatory if they reflect differences in the cost of service.

**Generation.** The generation of electricity,

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which is clearly separated from the wires service business, is in principle competitive. Two companies controlled 75 to 80 percent of the United Kingdom's capacity under the original privatization, with small additions available in Scotland, whose interconnection capacity is under expansion, and in France, via a channel interconnection. Nuclear plants, constituting 15 to 20 percent of capacity, continue to be owned by the government (no one wished to buy them).

Energy, with the exception of the administrative charge noted below, is priced in a free market. Each day, generation companies offer price schedules to supply power half-hourly from each generating unit for the following day. The pool price is the highest offer price accepted for dispatch. Those with lower offer prices all receive this common pool price; those that are higher are rejected.

A capacity charge, based on the "value of lost load," is added to the competitive short-run marginal price. The charge is set by the director general of electricity supply and is designed to represent the value of capacity. The charge is also intended to provide an adequate return on capacity and an incentive for new investment. While the intent is for the director general to review it infrequently, perhaps every five years, he has discretion to do so more often. The director gener-

al's extensive power to determine this charge is perhaps the greatest compromise of competitive principles in the U.K. system. This compromise was a response to the fear that the auction system would force prices down to the out-of-pocket marginal cost of energy, leaving no profit return on investment.

New generation capacity will be supplied only if some agent expects that the future pool price (including the capacity charge) will justify the investment. Generators are licensed, but this is an agreement to follow the rules, not a restriction on entry. Any licensed, electrically compatible generator can hook up to the grid provided there is excess transmission capacity.

**Power Contracts.** Generators can contract with local suppliers of power; such contracts have been written for up to five years. These are contracts for differences between the pool price and the contract price. Since the generator owner receives revenue from the pool at the pool price, the only payment necessary between the buyer and seller is the difference between the pool and contract price. Thus, if the contract price is  $C$ , the pool price is  $P$ , and  $C$  is greater than  $P$ , then the buyer pays the difference ( $C$  minus  $P$ ); if  $C$  is less than  $P$ , then the generator pays the buyer ( $P$  minus  $C$ ). Such contracts are simply a risk-sharing arrangement for smoothing cash flows; anyone, including people not in the electricity business, can enter into such contracts. All prices are public information, published in the newspapers; the London Futures and Options Exchange operates a market in electricity futures. Since the contracts are independent of the physical flow of power, they will be renewed only if they have risk-sharing value. With the deregulation of gas in the United States, buyers have come to rely on the spot market for gas, and less upon long-term contracting. Thus, it is an open question whether, and to what extent, electric power contracting will continue.

**Transmission and Distribution.** For the transmission and local distribution wires businesses, the most heavily regulated portion of the U.K. system, price-cap regulation, substitutes for U.S.-style rate of return regulation. Although the National Grid Company (the transmission system) is owned by the 12 regional electric companies (local distribution systems), the charges for the wires of both are subject to ceiling price caps. These may increase annually by an "RPI minus X" factor: the retail price index (RPI), less a target rate of real price decrease (X) to reflect pro-

ductivity gains. The price level and the "X" factor are subject to review approximately every five years. The intent is to provide, within these ceilings, an incentive to control cost. If you are able to reduce costs, you are entitled to keep the money.

The National Grid Company recovers its expansion costs through the ceiling price formula; in other words, if capacity is expanded and transmission revenues are inadequate to cover the cost of expansion plus a "reasonable" return on investment, the ceiling price cap will be increased. Indirectly, then, the grid is subject to American-style regulation for capacity increases and is subject to the well-documented hazards of such regulation.

**Determination of Retail Price.** Retail customers are billed by the local distributor (one of the 12 Regional Electricity Companies). The cost of the energy used (the pool price including the capacity charge) is passed through on a full-cost basis and is subject to no cross-subsidy (discrimination) license conditions. Similarly, the transmission charge is passed through to the customer. In addition, there is a charge for the use of the local wires that is subject to "RPI minus X" price ceilings. Within these ceilings, if a distributor is able to cut costs, the savings can be carried through to that distributor's bottom line.

During the first four years, the local distributor has an exclusive franchise to serve customers whose annual consumption is below rates of one megawatt. Larger customers can contract directly for power or buy spot power from the pool. When the franchise period expired in 1995, a market for small customers was free to develop. National chains of pubs, hotels and retail stores have moved to obtain single supply contracts for their various locations. Credit card companies, British Telecom, and others with established access to customers will be free to offer electric supply to individual households. Such third-party suppliers will simply pay the local distributor the wires charge and bill the customer for electricity supply. Customers will be free to invest in their own local wires and bypass the local distributor. Consequently, the markets for energy and distribution services will become contestable, with customers having a choice among alternative providers.

### Lessons from the U.K. Experience

According to Stephen Littlechild, director gener-

al of electricity supply in the Office of Electricity Regulation, the initial fear that under privatization no one would risk building new generation capacity has proven to be unfounded. As of 1994 his agency had issued 14 new generator licenses since privatization, bringing planned new capacity to 6,700 megawatts (MW), and construction was under way to increase the capacity of the Scotland interconnect to 1,800 MW. New capacity of 3,200 MW has already been commissioned, and the share of capacity by the two primary generating companies has declined from 75 or 80 percent to 61 percent. This share is likely to fall further.

Customer electricity prices declined about 15 percent during the first year after privatization. This was due largely to excess capacity built ear-

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lier by the nationalized industry, some of which was becoming obsolete at the time of privatization, but also due to the ability of customers to shop around. Some 30 percent of the large non-franchise sites went to sources of supply other than the local distributor. Prices were expected to rise as excess capacity was absorbed, and indeed this began to occur after the first year. Subsequently, prices started to increase significantly. The expectation of rising prices may have stimulated the new capacity now under construction. This interpretation is confounded, however, by the possibilities that the capacity charge has been fixed at a level more than sufficient to encourage new generators to be built, or that the short-run marginal price of energy was artificially inflated by market power exercised by the two generation companies that accounted for most of the capacity that was variable with demand. Evidence for the market-power interpretation is implicit in two tables by Littlechild comparing changes over time of the two companies' share of output and share of capacity: their share of output and capacity at vesting (1989-90) were equal at 78 percent, but by 1994 their share of output was down to 59.4 percent while their share of capacity had fallen to only 69 percent. Thus, it

would appear that as new entrants come in, the two companies (which account for almost all of the load-following generation) are restricting their use of capacity. Sooner or later, however, these new entrants are likely to induce a more rapid decrease in prices.

The good news is that inflation-adjusted prices have declined for all customer classes in Britain, except the largest industrial customers. Price increases for the latter are the result of the withdrawal of the special terms they had enjoyed under nationalization.

### New Zealand's Approach

The denationalization of electric power in New Zealand, still in progress, is modeled on the British system but differs in several features. Under the New Zealand proposal, the potentially competitive production and marketing of energy would be clearly separated from the more problematic wires business. But regulation of the latter would be even more light-handed than in the United Kingdom, in that there would be no central regulator comparable to the United Kingdom's Office of Electricity Regulation. Since the transition is still in progress, the final form that regulation will take is not certain. Hence, the following discussion primarily focuses on the reforms that have been proposed and are under discussion.

**Generation.** Competition in the wholesale market would be achieved by two policies: (1) open entry to the transmission/distribution grid by new generators; (2) breakup of generation capacity now held by the Crown-owned Electric Corporation of New Zealand (ECNZ).

The first provision is not controversial in principle, and will almost certainly be a cornerstone of the new privatized industry in New Zealand. In fact, new investments are already being contemplated by various private interests.

The second provision is more controversial, and the extent to which the ECNZ will be broken up has yet to be resolved. If generation is spun off into separate companies, no more than four or five such companies are likely to be formed, and in fact there will probably be fewer than that. ECNZ, while opposed to a breakup, has responded to a government request with a proposal that it retain a core of 22 stations, or 63.2 percent of total capacity. Under this proposal, ECNZ would continue as the dominant genera-

tion company under privatization.

**Wholesale Energy Market.** The pricing of wholesale power would be effected through a combination of a spot market for power, integrated with central dispatch, and "long-term" contracts for power between generators and distributors. The spot market will operate essentially as does the current engineering energy-cost minimization dispatch system except that decentralized generator owners will submit the offer price schedules at which they are willing to supply location-specific spot power to the grid. The dispatch center will accept the lowest-priced generators first, in order, up to the marginal generator required to meet demand. Higher-priced generators will be rejected, and the spot price will be the offer price of the marginal generator.

New Zealand, unlike the United Kingdom, is not proposing to add a capacity charge to the spot price, but of course this proposal is not looked upon with favor by the supply side of the industry. New Zealand proposes to use the market for "long-run" contracts between generators, distributors, and power merchants to provide a return on generation investment. Some contracts have already been written between ECNZ and the distributors, but according to R. S. Deane, former chief executive of ECNZ, the distributors refused to sign contracts for more than one year. While this has been a concern to ECNZ, the distributors' reluctance is hardly surprising, given ECNZ's initial surplus of generation capacity and the uncertainties of the privatization process.

**Transmission.** The high-voltage transmission network and the dispatch center would be constituted as TransPower, a private operating company jointly owned by the generation and distribution companies. Separation of the transmission system from ECNZ was postponed several times, but has now been effected. TransPower would not itself be involved in any energy transactions. Dispatch may be operated by TransPower or an independent agency. All generation and distribution entities, whether existing or new, would have nondiscriminatory access to the services of TransPower.

All TransPower prices, capacity charges, and hookup fees are to be cost-based and regulated through "transparency" and "public monitoring". Transparency means that all charges, the supporting cost allocations, cost computations, policies and audited financial statements are published in the *New Zealand Gazette* and available



to all interested parties. Public monitoring means that any interested party can, under the Commerce Act, formally complain to the Commerce Commission or a court, as appropriate. The burden would be on complainants to show that prices are excessive or discriminatory.

**Local Distribution Companies.** The 1989 Report of the Electricity Task Force called for distribution, which for 70 years has been operated by local municipalities, to be privatized, with direct ownership in the form of transferable shares. Exclusive franchising for both the local lines service and energy would be eliminated. This means that the entry of competing supply lines is not prohibited, although new lines connecting with an existing distribution network must meet the latter's technical standards. The task force recognized that the owners of existing lines have a "natural line franchise" which, because it is indeed natural, needs no legal protection. The threat of entry, being real and legally open, can therefore help discipline prices.

Along with exclusive franchising, the distributors' obligation to supply is eliminated. Historically, distributors were required to connect all who so desired. Remote, uneconomic customers paid the same average charge as all others under a regulatory formula. Removal of the obligation to supply means that this cross-subsidization would be eliminated: some customers will pay more and some less. Many subsidized customers filed opposing minority opinions. Whether this proposal will survive the political process remains to be seen.

Distributors must itemize bills to distinguish clearly the capital rental charge for the lines part of the business—both transmission and local—and the charge for metered energy. The cost of new or altered connections would also be charged to the customer.

**Power Merchants.** The New Zealand proposal has a novel feature: free entry by retail power merchants. Anyone will be free to buy power under contract or on the spot market, pay the local rental rate on wires, and go into the power-marketing business in competition with local distributors. Distributors cannot prevent entry by power merchants and must charge them the same cost-based rental rate—subject to challenge—that they charge their own retail customers. A power merchant passes through the distributor's rental charge for the wires. This renders the energy marketing portion of the business highly contestable.

New Zealand's 1989 reform agenda, to separate the local distribution lines business from the energy business, has now been implemented, and as of April 1994 the local monopoly retail franchise was eliminated. This is remarkable, given that the conventional wisdom alleges that distribution is a basic example of natural monopoly. Yet progress in restructuring the energy supply industry and the creation of an independent transmission grid has been repeatedly stalled. The political process has repeatedly stretched out the timetable for completing the privatization of ECNZ assets held by the Crown. In order to break the stalemate between the supply and wholesale demand sides of the industry, the government appointed a new Wholesale Electricity Market Development Group to oversee the detailed implementation of the wholesale market. One of its duties was the "adoption of a structure that cannot be dominated by any one organization or interest group." The development group has now filed its report to the Minister of Energy, and awaits the government's response.

### A Proposed Structure

In this section I propose a privatization model that shares some features with the United Kingdom and New Zealand privatization programs but makes greater use of markets to regulate electric power. The model retains the concept of separating the energy and wires service portions of the industry at both the transmission and distribution level. The discussion below addresses ways in which the operation of the market for energy and the structure of transmission and distribution can be configured so that market forces can substitute for (or supplement) the light-handed regulation used in the British or New Zealand models.

**Generation.** All generating companies would be for-profit private entities competing to sell energy on the spot market to retail power merchants and bulk commercial and industrial customers. They would also be free to negotiate contracts for differences, as in the United Kingdom. The generating companies would purchase location-specific power-injection rights to the grid. New, electrically compatible generators could enter freely, provided that they pay for capacity rights and for connection charges.

**Transmission.** The high-voltage transmission network, including the dispatch center, would be

owned jointly by retail power merchants, commercial and industrial customers, and, perhaps, as proposed in New Zealand, by the generating companies. (Politically, it may be difficult not to give generator companies a stake in transmission, although the cost of their stake will obviously be borne ultimately by the final customers.) The network, as a joint venture, would be an operating company run as a shared-resource cost center, not as a profit center. It would be constituted as a competitively ruled property-right system defined by the government, and not as an ordinary shared-ownership corporation.

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**The California Public Utilities Commission has announced its intention to allow electricity customers in that state the freedom to shop both inside and outside the state.**

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The property-right rules would have the objective of providing incentives for prudent investment and maintaining competition in the following manner. Historical capital cost and maintenance cost for the transmission system would be shared by the owners in proportion to their installed capacities to withdraw power from, or inject power into, the network. Capacity rights to inject (or withdraw) power represent rights to bid for the purchase of power (or offer it for sale) up to that capacity. Whether such bids (or offers) are accepted depends upon spot market competition at the time. Large customers, consortia of small customers, and new generators would also have access to the grid, subject to the payment of their direct connection costs and their share of grid capital and maintenance costs. Capacity expansion of any part of the grid would be the responsibility of any user or consortium of users willing to make the investment. In turn these users would obtain rights to the increased capacities made possible by the expansion. Users that are not part of the capacity expansion would have no rights to block expansion or demand compensation if the result is to shift the supply of, or demand for, power in favor of others. But they would be free to join the joint venture and to share in the creation of more favorably located grid rights. Network capacity rights could be

bought, sold, rented, or leased subject only to the antitrust laws that apply to any other industry.

**The Market for Energy.** The dispatch center, the core of transmission operations, would be responsible for economic dispatch and for the technical stability of the high voltage grid. Economic dispatch means the following: (1) retail power merchants would submit bids to the center for various quantities of power delivered to specific points during half-hourly market periods; (2) generators would submit offer schedules to the center specifying the prices they would be willing to accept for various quantities of power injected into the network at specific locations each half-hour; (3) the dispatch center would then apply standard optimizing algorithms to these bids and offers to determine one market-clearing spot price, which is then location-adjusted for incremental transmission losses at each node. Simultaneously, the algorithms determine which generators are to be active, and their respective power-injection levels. Note that bids to buy above the spot price pay only the spot price, and offers to sell below the spot price all receive the spot price. A high bid simply assures that the bid will be accepted. Similarly, a low asking price offer by a generator assures that the offer will be accepted. There is no price discrimination among buyers and sellers, as all price differences reflect incremental transmission loss. The algorithms maximize the gains from exchange based upon the bids, offers, and the energy loss characteristics of the transmission system. Since transmission losses would be reflected in the wholesale spot price at each take-off or injection node in the network, they would be paid by the retail merchants and, ultimately, by their customers. The spot market would be supplemented by technical futures markets to facilitate the planning of generator commitment and its coordination with maintenance outages. Thus, a generator completing maintenance and requiring several hours for start-up is free to contract ahead for an assured revenue before incurring the start-up cost.

Except for the addition of active buyer bidding, the dispatch process does not differ from the long-standing practice of engineering dispatch that minimizes fuel costs plus transmission losses in integrated systems. Generator owners, however, would be free to select the terms on which they are willing to supply power. There is no requirement that their offer prices conform to

their marginal cost of fuel, since their price must not only cover fuel costs, but also capital and maintenance costs. Generator owners would be free to enter into financial hedging contracts with buyers, as in the United Kingdom, but not into bilateral (physical flow) capacity contracts, since the latter would inefficiently constrain the dispatch center's system-wide optimization objective.

The above structure relies on the creation of fungible capacity rights to jointly owned transmission facilities. Although the use of such rights as an explicit instrument of competition may be novel, joint-venture arrangements are commonplace in the U.S. utility industry. Generating plants and power lines are often owned under cotenancy contracts between two or more companies. They are not, however, competitively ruled by property-right specifications like those articulated above.

At present, utilities are commonly exempt from antitrust laws because they are regulated. In the above structure, all parties would be subject to the ordinary antitrust laws applicable to any other industry. Cotenancy arrangements would be strictly production joint ventures, and any marketing agreements among the competing cotenants would be forbidden, as in any unregulated industry.

**Distribution.** New Zealand's experiment with restructuring distribution so that decentralized economic and judicial processes are given an opportunity to discipline costs and prices, suggests one proposed initiative for the privatization of distribution. Elsewhere (see "Selected Readings" on page 46), I have proposed a competitively ruled cotenancy (or joint venture) property right system for distribution that is parallel to the above proposal for transmission.

### **New Developments in the United States**

The United States has not been immune to the above international trend, although we are among the last to join it. Increasing pressure from consumer interests resulted in the Energy Policy Act of 1992, passed at the end of the Bush administration. This act requires utilities, most of which share in the ownership of the transmission system, to permit customer access to other utilities and to the growing number of independent power producers. It sets the stage for multi-lateral long distance competition among energy

consumers and producers connected to the power grid. Customers served by a local utility at high rates could buy power from other, lower-cost sources by paying a small transmission user fee. The California Public Utilities Commission has announced its intention to allow electricity customers in that state the freedom to shop both inside and outside the state. Beginning in 1996, the largest industrial customers will be able to choose any supplier of energy. In the following years, free access will be expanded to smaller industrial customers, then commercial customers, and finally to all residential customers by

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2002. This competition is likely to yield lower prices in the current environment, in which there is a surplus of power. The short-run impact will erode overall electric utility profits, with differential impact on individual firms, but the long-run effect will be to lower cost and bring capacity into better balance with demand. This development almost certainly means that other western states will increase their participation in the California market by increasing exports of power.

These trends are opposed in both the industry and the regulatory commissions, but opposition by those threatened by these changes seems unlikely to prevail, although it certainly can delay needed reforms. Technological and organizational innovation has caused the traditional regulatory apparatus to become obsolete. If regulators are to promote the consumer interest, which is their traditional charge, then it is incumbent upon them to ask how they can facilitate reforms. Yet the trends discussed above undermine the need for regulators in their traditional role; their self-interest in the perpetuation of the regulatory apparatus is in conflict with the consumer interest, and is more compatible with the interest of those utilities opposing competition. That is why reform may be slow, highly controversial, and require transition-easing mechanisms.

An important consideration—and a point of contention—in the United States is the question

of how transmission costs are to be allocated among users. The proposal outlined above, in which the high voltage grid is jointly owned by the users in proportion to their respective capacities to inject (or withdraw) power at specific nodes, is conceptually easier to implement in countries like New Zealand, in which the government now owns the grid. The government can simply elect to sell joint-venture rights to the grid in proportion to status-quo capacities to inject or withdraw power, and thereby constitute the grid as a rule-governed joint venture of the users.

Although it is possible in principle to apply this conception to the American scene, the devil is in the details. The grid is already balkanized into pieces

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**Central coordination is necessary in electric power because electrons flow according to the laws of physics, not economics.**

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privately owned by existing utility companies. To create a joint venture such as the one envisioned above, each utility would acquire use rights to the rest of the grid in return for giving others use rights to its own grid. But in the U.S. environment, one in which some utilities have invested more extensively in transmission than others, this would require compensation through transfer payments. Guidelines for compensation are no doubt implicit in existing contracts for grid rights and in historical capital investments, but making such rights permanent on a voluntary basis, to create a competitively ruled joint venture, is sure to be a Herculean task. Short of this, what seems likely to prevail is some form of federal regulation of transmission charges with its inevitable costs and concomitant incentive problems.

The current state of our research knowledge of electric power markets, based on foreign experience and limited laboratory studies, suggests that the final form of a deregulated electric power industry in the United States should respect, at minimum, the following considerations.

### **1. Computer-Based Regional Dispatch of Energy**

It is important to recognize that central dispatch should not constitute central control. It is simply rule-governed nerve-center coordination, based

entirely on the bids to buy power, and the offers to sell power or transmission services, by decentralized competing owners. Attempts to use the "pool" or exchange to impose rules that are a disguised attempt to perpetuate regulation, or forms of political bias favoring particular interests, must be vigorously resisted. In electric power we are, and should be, talking about the development of a property-rights system—rights to inject or withdraw power, rights of transmission access, rights to invest and to claim the benefits (and incur the losses) that accrue to such investment.

Central coordination is necessary in electric power because electrons flow according to the laws of physics, not economics. Hence, the market institutions must honor these technical considerations. Every industry has its own technical peculiarities that are reflected in its economic institutions, and electric power is particularly sensitive to special technical considerations. The stability and viability of electric networks simply cannot be respected if power injections and withdrawals occur without coordination. But there is a fine line between actions needed to protect the integrity of the grid, and those that serve to raise prices and protect revenues by restricting flows in the name of stability.

### **2. Open Entry to Buy, Sell, and Transmit Power**

A privatized industry, one in which prices and services are regulated predominately by a market, must be open to entrants that wish to consume, produce, or transmit power, subject to electrical compatibility standards. This means that new generation capacity is built at the financial risk of the investor, not the rate-payer, as in U.S.-style regulation (or the taxpayer, as in the case of government ownership). Similarly, buyers incur the risk of investing in energy-using equipment subject to unforeseen changes in future energy prices. All new capital investments in the electric supply industry should therefore meet a competitive market test.

### **3. Demand-Side Bidding**

From its inception, the concept of a computer-based energy-dispatch auction market should make provision for demand-side bids to buy, as well as supply-side offers to sell. This is because there is much

experimental/empirical evidence to show that two-sided markets are more competitive and provide better discipline of market power than one-sided auction markets. When wholesale buyers have the option to enter demand bids, this increases their incentive to estimate more accurately their demand, and to invest in demand-interruption technologies, which allow them to make savings at high on-peak prices. These incentives to manage demand, in turn, save on the need to invest in new peak-load generation and transmission capacity, thereby also automatically providing better protection of the environment.

#### **4. Contracts as Financial Instruments for Hedging against Risk**

People want, and should have available, contracting instruments that enable them, at a price, to protect against unanticipated movements in energy prices, and enable them to better plan their business activities both in the short run and over more extended periods of time. Thus, long-term contracting can take the form of (but need not be restricted to) the financial instruments used in the United Kingdom and elsewhere, in which a fixed-price contract leads to bilateral payment transfers when the spot price differs from the contract price. Because bilateral contracts for physical delivery limit coordinated dispatch, they can yield infeasible, and potentially unstable, system requirements. Deliveries should reflect the economic and physical realities expressed by agents in their spot market bids and offers, whatever might be the additional financial contracts they might have entered into at an earlier and more uncertain time.

#### **5. Prices at Different Location Nodes in the Network Must Reflect the Marginal Cost of Energy Lost in Transmission.**

This is accomplished under "nodal pricing" using computer-based dispatch. That is, the dispatch center takes into account the higher transmission cost of energy generated at more remote locations. Such "distance price" concepts are important in providing better incentives for locating new generation sources, as well as new energy demand loads, so that energy is not wasted.

#### **The Politics of Transition Mechanisms**

The existence of stranded assets—inappropriate

sunk investments encouraged by the disincentives of regulation and past government energy policies—has created a demand for compensatory transition mechanisms as a prerequisite for deregulation. Some accommodation of these forces seems to be politically necessary. The natural transition mechanism for getting the right incentives is to convert current monthly billings into a two-part charge: a fixed-use charge to recover the amortized sunk cost and a per-unit charge for energy consumed. The fixed charge would go to zero after the stranded investments have been recovered. In the meantime, cus-

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**Energy customers, who compete in a world with no state-supported mechanism for recovering the cost of their investment mistakes, would be loath to pay for the mistakes of others.**

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tomers who paid the fixed-use charge would be free to purchase energy in the market from any supplier. Any new capital investments would have to earn their keep from the energy price, as, eventually, would all future investments, once the stranded assets have been recovered.

The problem with this theoretical mechanism is in the devilish details. The severity of the stranded-asset problem varies enormously among states and among utilities within individual states. Those utilities that have already gone through de facto bankruptcy and restructured their debt and equity have already made the transition, and stockholders have taken the hit; others have enormous stranded-asset liabilities and would require large fixed-use rates. This can result in substantial differential treatment of different utility customers, with market incentives likely to cause leaks in the dikes erected to protect the cost recovery of past investments. Industrial *customers*, who compete in a world with no state-supported mechanism for recovering the cost of *their* investment mistakes, would be loath to pay for the mistakes of others.

The lesson in all this is to avoid future regulatory intervention into markets. Better to live with temporary monopoly, subject to free entry, than to attempt to regulate it in what has been alleged to be the "public interest."

Over a century of change in the electrical

power industry has brought us full circle. Throughout the world we see a return to structures more open to regulation by market competition than at any time since the industry's inception. The form of competition today, however, will necessarily differ from that which prevailed at the beginning, because of intervening technological and institutional change. Many questions concerning the detailed architecture of the new industry cannot be answered by anyone at this time, although provisional answers are in the process of being developed, and the knowledge gained from the variety of recent worldwide experiences is being assimilated. These developments are converging, but are not likely to yield a single, universal solution, because different countries have started with different initial conditions that require accommodation.

### Selected Readings

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