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Power Struggles: Explaining Deregulatory Reforms in Electricity Markets

SINCE PASSAGE of the Federal Power and Public Utilities Holding Company Acts in 1935, the electric power industry has remained one of the most tightly regulated sectors of the U.S. economy. Through lengthy and litigious proceedings, state and federal regulatory commissions adjudicate the prices, capital investments, financial structure, and corporate organization of the 250 investor-owned electrical utilities that principally operate as *de jure* or *de facto* franchise monopolies. After more than a decade of deregulatory activity in other traditionally regulated industries, similar policies are now being pursued for electricity. Federal legislation in 1992 expanded competitive opportunities for wholesale electricity producers, leaving states with the option to pursue regulatory reform of retail electricity markets. Legislative and regulatory policymakers in more than a dozen states are now considering whether to deregulate prices and entry for retail electric power service; the most aggressive states are pursuing policies to allow retail competition to begin in 1998.

In the states where a broad consensus for electricity industry ''restructuring'' has evolved, to use regulators' preferred moniker, a broad consensus also has emerged on the fundamentals of how such restructured markets should be organized. In large part this accord reflects the

I am grateful to Lisa Cameron for generously providing data on the independent power contracts listed in table 1, and to Paul Joskow, Jerry Hausman, and Peter Reiss for valuable comments on an earlier draft. I thank Elizabeth Demers and Michael Ting for excellent research assistance.

viability of competition for different segments of the services provided today by vertically integrated firms. The "standard prescription" for the reorganization of the electric power industry is based upon the vertical unbundling of the generation and sale of power from its delivery (that is, regional transmission and local distribution) to consumers.[1] Technological change has reduced the economies of scale in power generation to a fraction of what they were in preceding decades, and the technological impediments to decentralized production across a common delivery network are surmountable. Transmission and distribution networks are nearly universally viewed as natural monopolies, however, and for the foreseeable future the delivery services they provide will be subject to the full panoply of regulatory activity historically imposed upon franchise monopolies. As a result, various forms of price and entry deregulation of power production (and marketing) essentially circumscribe the scope of potential competition under consideration. In the spirit of reforms in the telecommunications and natural gas industries a decade earlier, these changes generally envision retail service competition in which local distribution companies will provide network access and local transportation services but will not remain monopoly sellers of the underlying electricity commodity.

These changes in the electric power industry arrive on the heels of more than two decades of deregulatory activity in the communications, transportation, energy, and financial services industries. In some respects they constitute the ultimate endeavor of this "deregulatory revolution." Electric utility retail sales of $208 billion in 1995 amounted to more than 3 percent of gross domestic product (GDP), considerably exceeding the revenues of other industries subject to recent deregulatory efforts: long-distance telephone ($71 billion), local telephone service ($76 billion), airlines ($84 billion), natural gas supply ($70 billion), and truck and rail freight transportation ($125 and $29 billion, respectively).[2] Despite these precedents, for technological and political rea-

1. The "standard prescription" term is borrowed from Joskow (1996).

2. Detailed financial data on the electric utility industry are published annually in EIA (1995b); the other figures are drawn from the *Statistical Abstract of the United States* (1995, tables 699, 902, 1062, 1051, 1055, and 976). Telecommunications, airlines, rail, and natural gas revenues are (unadjusted) 1993 data; trucking (motor freight transportation) are 1992 data. Local telephone includes network access revenue (which is not counted in long-distance service revenue) and excludes $31 billion in cellular, directory advertising, and other revenue.

sons electric power has until recently presented a Gordian knot to advocates of industrial deregulation. The dramatic regulatory reforms now beginning to be implemented in the power industry were almost entirely unforeseen less than a decade ago.[3]

In this paper I provide unique state-by-state evidence on the distribution of potential gains to consumers (and losses to utilities) from these deregulatory reforms, and I advance several economic arguments to explain why these reforms are now being adopted. The focus of these arguments is why regulators are promulgating deregulatory reforms, and why these reforms are being implemented in some states but not in others. In contrast to the wave of federal deregulatory activity of the previous two decades, regulatory reform to admit retail competition in electric power is proceeding at the state level. For statutory reasons this is not entirely surprising, but it does raise the interesting matter of the diffusion of regulatory change across the states. I highlight the economic forces that are abrading the Gordian knot and examine why, after sixty years, it is now likely to be cut in many places.

The empirical development that spurred recent interest in electricity industry restructuring is a discrepancy between the regulated prices of incumbent utilities and the prices widely expected to prevail in a deregulated market equilibrium. Rather than limit prices below those that consumers would face in an unregulated marketplace, the apparatus of regulation increasingly maintains prices above the level that would prevail in its absence. Although consistent with a long line of regulatory theories dating back to Stigler's "capture" theory of regulation, this price gap stems from a more palpable phenomenon of steep declines in the capital cost of new plant.[4] Given the long-lived nature of incumbents' sunk assets and regulators' practice of average-cost pricing (and penchant for notoriously slow depreciation schedules), many incumbents now face a hitherto unseen form of technological overhang: new power production facilities can be developed by entrants at average costs well below those of many incumbent utilities.

Although this *bouleversement* can be traced to technological, economic, and political factors, the net result is a substantial increase in the opportunity cost of continued statutory entry barriers and political

3. See, for example, Joskow (1989, 188ff.).
4. Stigler (1971).

pressure on regulators to close the price gap. After providing some background information in the next section, I examine the causes of this price gap and estimate its magnitude for different states. These estimates reveal fairly dramatic differences in the price gap across states. In high-cost states they suggest strong incentives for consumers, and certainly for new producers, to press for regulatory changes to admit competitive entry.

Fingering this price gap provides less than a fully satisfactory explanation for the deregulatory reforms currently visiting this industry, however. In particular, it does not explain why regulators would pursue deregulatory reforms to admit competitive entry instead of simply closing the price gap, using existing regulatory instruments to bring incumbents' prices into line with market expectations. To address this explanatory lacuna, this paper offers a mechanism by which the price gap yields deregulatory outcomes as an adjustment response. The essence of this adjustment mechanism is that regulators prefer to ease political pressure for lower prices without resorting to costly alterations to the structure of regulation. Their ability to reduce this pressure by adjusting prices, however, is subject to certain institutional constraints.

The principal manifestation of these constraints is an obligation to provide a fair rate of return on the prudently incurred investments of the regulated, which in this industry are largely sunk. With a small price gap, this constraint is nonbinding, and regulators can restore political equilibrium with price decreases. When the opportunity cost of the price gap becomes sufficiently large, the institutional obligation to provide a fair rate of return presents a binding constraint on downward price adjustments, requiring the regulatory system to undergo structural changes to accommodate deregulatory reforms. The result is a certain hysteresis in the effect of the price gap on regulatory reform. Data detailing the average accounting costs for incumbent utilities indicate that, in more than one-third of the states in the United States, entrants can expect to profit at prices that would yield a zero economic return to incumbents. The demand for regulatory reforms in high-cost states can no longer be accommodated within the existing structure of regulation.

While short of a full-blown theory of regulatory change, this regulatory adjustment hypothesis does begin to reconcile certain observations about the deregulatory process. Most important of these is the widespread heterogeneity across states in the degree to which regulatory reforms are being pursued. To date, aggressive regulatory restructuring proposals have been adopted in California and a handful of New England states, and decisions to do so are pending in perhaps a dozen states. In many states, however, the legislatures and utility regulatory agencies show little eagerness to upset their basic regulatory system for electric utilities. Is this heterogeneity in regulatory reform outcomes a hallmark of a politically stable new industrial organization? Or is it simply a transitional state in a dynamic but inexorable diffusion of regulatory reforms nationally? I conclude that the data are more consistent with the former interpretation than with the latter.

The preceding arguments leave one important issue to be reconciled, however: recent regulatory decisions regarding the costs of assets left "stranded" by regulatory policy shifts. With few exceptions, policymakers in states pursuing aggressive deregulation plans have adopted positions to continue to allocate to consumers the outstanding (accounting) costs of sunk utility investments in long-lived generation assets. Normative questions aside, the effect of such policies is to delay the downward adjustment of consumer prices otherwise predicted by the political *tatonnement* of deregulatory reforms.

At one level, easy-to-find answers reconcile these policies. Utilities have thrown considerable resources into lobbying to recover sunk costs, and they have successfully steered the regulatory process as a result. Such superficial explanations beg the deeper question of what objective of regulators is being satisfied with these decisions. The standard prescription for the restructuring of this industry is being promulgated by regulators, not the regulated. These policy initiatives are rather costly, and on the matter of stranded costs have generated virulent political conflict in the regulatory arena. The vexing question is why regulators, who are ultimately political actors, would pursue costly restructuring proceedings that over the next several years apparently benefit no one.

The explanation is that the standard prescription for the reorganization of this industry provides a means for regulators to reduce their downside political risk without substantially lessening their regulatory authority. In states where deregulatory reforms are occurring, the principal source of political conflict for regulators over the past two decades has surrounded overbudget new generation facilities and regulators' commensurate obligation to allow utilities to recover their prudently incurred costs. The standard prescription being promulgated by regulators, in contrast, entails no such obligation. That is, regulators are shifting from a system in which they are obligated to assure producers of an *ex post* zero economic profit on capital investments to one in which they need only assure investors of an *ex ante* zero economic profit.

Shifting this economic risk away from consumers and toward financial markets eliminates regulators' principal downside political risk, and one inherent in the cost-plus system of utility regulation. Moreover, in lessening statutory entry restrictions, regulators have shown no sign of withdrawing their authority to exercise the visible hand should the marketplace fail to bestow its benefits in a suitably prompt and equitable fashion. In fact, the reform proposals being promulgated by regulators are more akin to reregulation than deregulation, where regulators eliminate the obligation to provide a fair rate of return on investments in future power production facilities in exchange for relegating their pricing activity to market oversight. Although this option has considerable value in states that have historically experienced cost overruns and the ensuing political conflict from above-market power prices, it has relatively little value in states that have not. In these states the price gap (and potential consumer gains from competitive entry) are negligible.

Regulatory Restructuring: Major Developments

Although electricity is principally delivered by franchise monopolies, competition already exists along limited dimensions within the industry. Most prominent among these is competition for power sales from new generation capacity. The Public Utilities Regulatory Policy Act of 1978 (PURPA), nominally designed to promote renewable energy sources and efficient cogeneration technologies, opened the door to competition for new generation by giving "qualifying facilities" the right to sell power to vertically integrated utilities. The act, in its various and sundry implementations by states, led to dramatic growth in the business of nonutility power generation in regions with high-cost incumbent utilities.[5] Despite considerable financial consequences for

5. For detailed discussions of the impact of PURPA, see Joskow (1989, 1991).

certain utilities, the act's direct contribution to industry competition has been limited by two factors: it neither allowed entrants to contract directly with consumers, nor permitted them to sell outside the service territory of the host utility. Nevertheless, PURPA has had one widespread impact: it demonstrated the viability of competitive entry into the capital-intensive power generation business.

Recognizing as much, Congress expanded the opportunity for unregulated entry into wholesale power generation by passing the Energy Policy Act of 1992. While not altering the first of PURPA's two competitive limitations, it effectively repealed the second. Specifically, it granted to the Federal Energy Regulatory Commission (FERC) the authority to order vertically integrated utilities to transmit power for others over regional transmission lines, the essential "bottleneck" facility necessary for robust wholesale competition. The commission's implementation of this authority mandates that owners of regional transmission networks act as common carriers of electrical power, providing interconnection service between independent power producers and wholesale buyers on the same terms and conditions with which it provides such service to itself.[6]

Although common carrier regulation of electric transmission networks is an important foundation for the development of competitive power markets, expanded network access in the $43 billion wholesale power market is unlikely to have much immediate impact on consumers. The Energy Policy Act specifically left the deregulation of retail electricity sales to the discretion of the states, maintaining the broad jurisdictional separation between the FERC and state regulatory commissions over wholesale and retail markets, respectively. Until recently, few states chose to pursue more than limited "retail-wheeling" experiments in which select (typically industrial) customers are allowed to contract for power from a supplier of their choice and to pay only connection and transmission ("wheeling") charges to the local utility.

One example is the Michigan Public Service Commission's five-year retail competition "experiment" permitting power supply procurement from an out-of-state utility for a handful of auto factories and industrial facilities.[7] Adoption of such supplier-switching options has been

6. 75 FERC ¶ 61,080 (April 24, 1996), Docket No. RM95-8-000.
7. EEI (1996, pp. 78–82).

resisted by regulators in other states because it raises controversial cost-reallocation issues within the context of traditional regulatory price-setting practice. For example, Connecticut's utility commission rejected a similar proposal in 1994, concluding that "the introduction of open generation competition for retail sales is not in the best interests of the stakeholders, State Energy Policy, and the economy of the State of Connecticut."[8] Evidently, Connecticut's regulators deemed the invisible hand not to be a viable substitute for good-old Yankee ingenuity.

The watershed event occurred in April 1994, when the California Public Utilities Commission released an aggressive plan to deregulate the power generation business in that state.[9] The plan followed a 1993 staff report that characterized California's particularly activist form of electric utility regulation as ill suited to govern the evolving power industry and fundamentally incompatible with the industry structure likely to emerge in the future.[10] Long a bellwether agency, the California commission's proposal envisioned unbundling the generation and sale of electric power from its transportation and distribution, with price and entry deregulation for the former and a hybrid of common-carrier and regulated-reseller treatment for the latter. To facilitate competition in generation, the plan proposed creation of a statewide day-ahead anonymous power exchange, or "pool," which would clear bids to supply power in each hour of the succeeding day against forecasts of consumer demand. The existing utilities' regional transmission networks would be horizontally integrated under the aegis of an independent system operator, or ISO, a regulated entity unaffiliated with any buyer or seller and charged with the responsibility to ensure that any schedule for power deliveries does not violate the physical integrity of the power network. Individual consumers would have the opportunity to contract with suppliers outside the pool and to schedule delivery through the ISO (subject to various restrictions). It is expected, however, that for some time the majority of consumers would continue to be served by regulated local distribution companies offering bundled energy and energy-delivery service. The energy commodity component

8. Connecticut Department of Public Utility Control, Docket No. 93-09-29 (August 5, 1994), p. 76.

9. California Public Utilities Commission, R.94-04-031 and I.94-04-032 (April 20, 1994).

10. California Public Utilities Commission (1993).

of this bundled service would be offered at the average pool price, but the price of delivery-related services and other charges (metering costs, subsidy programs, and so on) would continue to be set by regulators.[11]

This sweeping proposal to reorganize the power industry in California had a stunning financial impact on the state's electric utilities. When California's regulators began developing their deregulatory reform proposals at the end of 1993, California's three investor-owned electric utilities had a combined market value of more than $30 billion. This value plummeted more than $12 billion over the ensuing six months as the plan was developed and formal industry restructuring proceedings commenced, a staggering loss during a time when the market as a whole remained flat. Successive developments have battered these three high-cost incumbents; in January 1996 the California commission affirmed its plan and set January 1998 as the date by which consumers would have the ability to purchase electricity from a supplier of choice.[12] In response to this affirmation, the Pacific Gas and Electric Company, the largest utility in California, announced write-downs in March 1996 and saw its stock fall more than $1 billion in a single day.

Subsequent legislative activity tempered the effects of these regulatory reforms on incumbent utilities' near-term revenues. In August 1996 the California legislature enacted the regulatory reforms proposed by the California Public Utilities Commission and stipulated that California's incumbent electric utilities be allowed to recover the costs of prior investments in power production resources rendered unprofitable by these policy changes.[13] This stranded-cost recovery proviso delays any significant effect of regulatory reform on end-user prices until well after the turn of the decade, and it reflects an intense damage control effort by incumbents in response to the shifting regulatory landscape. Nevertheless, since the California commission's electricity market restructuring proposal was signed into law, the market values of that state's

11. The development of the California Public Utilities Commission's plan, at least in its original (1994) form, drew heavily on the organization of the U.K. power market after privatization in 1990. On the latter, see especially Newbery (1995) or Armstrong, Cowan, and Vickers (1994). Substantial deregulation and privatization of the electric power industry have taken place in Norway, Argentina, Chile, and New Zealand in recent years. See Gilbert and Kahn (1996) for surveys.

12. California Public Utilities Commission, R.94-04-031 and I.94-04-032 (December 20, 1995, as modified January 12, 1996).

13. California Assembly Bill 1890, which became law September 23, 1996.

utilities have settled down to about 20 to 30 percent below their position when the process began in 1993. The decline represents billions of dollars in forgone expected earnings and reflects the fact that the long-term market structure now facing incumbents is very different from that under traditional regulatory practice. The summary conclusions from California are twofold: on balance, the changes being promulgated by California regulators are not being undertaken for the benefit of utility investors or employees; and, in the opinion of financial markets, the prices ultimately likely to prevail in a deregulated power marketplace are well below those expected under continued practice of status quo regulation.

Since the January 1996 affirmation of the California decision, broadly similar policies have been adopted in Massachusetts, New York, and New Hampshire, with qualitatively similar responses from financial markets. What is likely to happen in the states between California and the Northeast, however, remains an open question. Regulatory or legislative bodies in more than forty-five states have commenced inquiries or proceedings on utility industry restructuring, but most have taken a far more cautious approach to regulatory reform than that in California and New England. The removal of legal barriers to entry is only the first of many hurdles to be surmounted in order to achieve the reorganization of this industry proposed in California. Many states appear to be waiting to see how successful California will be at overcoming the numerous contractual, organizational, and logistical issues that remain. Moreover, in many states it is far from clear that there exists sufficient incentive for consumers, regulators, or utilities to pursue such costly reforms, or to support federal intervention that mandates such changes. The Utilities and Transportation Commission in the state of Washington completed a formal inquiry into competition in electricity markets in December 1995 and concluded that no radical changes of the sort in California were warranted. Three months earlier legislators in North Carolina voted against even opening formal inquiries in the matter. And in January 1996 the South Carolina Public Service Commission issued an order concluding that regulation had "worked well" in the state and that "pressures for regulatory change are . . . concentrated . . . where regulation [has] failed and undue costs have been loaded onto electric rates."[14]

14. EEI (1996, p. 127).

The states' divergent perspectives on the merits of regulatory reform can be quickly traced to obvious differences suggested by South Carolina's observant regulators. To a greater degree than elsewhere, regulators in California and New England face an increasing disparity between the retail price of electricity and the price of power procured from regional wholesale markets. The disparity in prices is evident from the consistent margins by which now competitive power solicitations under PURPA underbid proposed utility projects, and from the price of bulk power in regional interutility wholesale transactions. In the past few years these retail-wholesale price differences have become increasingly transparent, fueling a demand for retail competition to redress this phenomenon. The Dow Jones Electricity Price Index, published daily in the *Wall Street Journal*, is a noteworthy example. During 1996, the index price for power delivered at the California-Oregon border averaged 1.6 cents per kilowatt-hour (KWh) on peak hours and 1.0 cent per KWh off peak hours; the California investor-owned utilities that are the principal buyers of this power resell it at retail prices averaging 9.8 cents per KWh.[15]

There is more motivating regulators' desire to restructure electricity markets than the price differences among regional utilities and the demands of politically vocal consumers to arbitrage them. The conclusions of regulators in California and New England are that competitive entry into power generation is viable and that the *tatonnement* to a deregulated market equilibrium will dictate changes in the price of power more efficiently than regulators' visible hand. Why the retail price of electricity in a competitive marketplace should be less than that of regulated incumbents' requires some explanation, and this I turn to in the next section. Later in the paper I address the question of why certain regulators now view market forces as a more efficient means of altering prices than the established institutions under their command.

The Price Gap Problem

The gap between the regulated prices of incumbent utilities and those expected to prevail in a deregulated market equilibrium has spurred

15. EIA (1995a, table 7).

recent interest in electricity market restructuring. In this section I examine the causes of this price gap and provide direct evidence on its magnitude for forty-five states considering regulatory reforms. Assessing these causes requires consideration of entry and its ability to discipline prices in unregulated power markets and of the constraints and opportunities facing incumbents under status quo regulatory practice.

Entry and Deregulated Market Equilibria

The dockets of regulatory restructuring proceedings are littered with assertions that unfettered price competition among the owners of generation assets will lead to welfare gains as production is reallocated from high-cost to low-cost firms. Such assertions beg a more serious inquiry into where the benefits of deregulation are likely to arise. Over the years utilities have established an extensive system of wholesale markets, power pools, and other institutions through which they engage in a great deal of interfirm trade. These markets are anything but thin in many regions and are quite successful at exploiting short-run marginal cost differences among utilities, subject to spatial limitations on trade. The clear but oft-overlooked consequence is that further gains from short-run price competition among incumbents in the elaborate spot power markets contemplated by policymakers are likely to be minimal.

Instead, the benefits of deregulation are predicated on the viability of competitive entry. Despite the robust nature of existing wholesale markets, transmission network constraints confer upon many incumbents considerable local market power. Concentration of existing generation assets among incumbent utilities (or successor subsidiaries) implies that potential entrants willing to make new capital investments will present an essential means of disciplining deregulated incumbents' pricing behavior in generation markets. Moreover, given the spatially constrained productive efficiency of wholesale markets, the productive efficiency gains of deregulation will be principally determined by the ability of these entrants to produce at a lower cost than incumbents (or, to be more precise, than the costs incumbents will incur in the absence of regulation).

The benefits of electricity deregulation thus hinge upon two fundamental premises: entrants can produce at average costs less than those of incumbents (or at least a meaningful subset of them), and the barriers to entry are sufficiently low that entry can drive the long-run price of power below the level likely to prevail in the absence of regulatory reform. The first of these conditions, in particular, represents a dramatic change in the economics of entry from the preceding five decades. The development and refinement of aircraft engine derivative-generation technologies, principally the single and combined-cycle gas turbine, have made entry feasible at modest scales (50 to 250 megawatts) and with relatively short lead times (twenty-four to thirty-six months)—commensurately reducing the risk in entrants' fixed (capital) expenditures. Unlike the mammoth power plants fashionable in the past, these technologies increasingly represent standardized, off-the-shelf products supplied by a competitive market of more than 100 firms.[16]

Complementing these developments is a substantial change in the relative prices of fuels: since the mid-1980s the wholesale price of natural gas has declined dramatically, both in absolute (real and nominal) terms and relative to competing alternatives such as coal. These changes in worldwide energy markets have magnified the economic advantage of newer "small-scale" production technologies relative to the existing capital stock of incumbents. With the historically low expectations for future natural gas prices and the deregulation of wholesale gas procurement in the United States, the industry is now facing a situation where entrants are expected to produce at an average cost well below that of many incumbents.

Data that permit direct estimation of the probable average costs of entry are difficult to obtain, but some information can be gleaned from the prices in power sales contracts held by existing nonutility generators. Table 1 presents data for a sample of competitively awarded contracts for the sale of power from nonutility generators to vertically integrated utilities under the Public Utilities Regulatory Policy Act of 1978.[17] The standard procurement procedure for such contracts involves state regulatory authorities' administrative determination of a utility's (the prospective buyer's) "avoided cost," nominally intended to be the long-run average cost of a new increment of capacity as would be

16. Joskow (1991, p. 69).

17. Since 1988, competitive procurement of new generation capacity has been the norm for many utilities, including PURPA purchases pursuant to a revised interpretation of that legislation by the Federal Energy Regulatory Commission.

Table 1. Competitive Power Solicitations: Reservation Prices and Awarded Contract Prices

Buyer	*State*	*Year*	*Capacity solicited (MW)*	*Capacity offered (MW)*	*Number of bidders*	*Number of contracts awarded*	*Average price of awarded contracts (¢ per KWh)*	*Reservation price (avoided cost) (¢ per KWh)*
Eastern Edison Co.	Mass.	1987	30	180	11	2	4.11	5.55
Commonwealth Electric Co.	Mass.	1990	110	920	28	1	4.14	5.69
Public Service Electric & Gas	N.J.	1989	200	1,063	17	2	4.27	4.97
Niagara Mohawk Power Co.	N.Y.	1989	350	8,700	105	1	4.39	7.14
Jersey Central Power & Light	N.J.	1989	270	768	19	3	4.80	5.88
Orange & Rockland Utilities Co.	N.J.	1989	150	1,425	40	2	4.92	5.20
Eastern Edison Co.	Mass.	1989	30	337	14	1	5.02	5.28
Long Island Lighting Co.	N.Y.	1989	150	1,770	21	1	5.21	5.96
Boston Edison Co.	Mass.	1989	200	2,800	48	1	5.24	6.56
Commonwealth Electric Co.	Mass.	1988	110	1,044	31	3	5.28	6.41
Consolidated Edison Co.	N.Y.	1989	200	3,096	36	3	5.66	8.94
Virginia Electric & Power Co.	Va.	1988	1,750	14,000	96	18	5.77	5.96
Virginia Electric & Power Co.[a]	Va.	1986	1,181	5,000	24	7	6.07	5.79
Boston Edison Co.	Mass.	1987	200	1,800	61	8	6.75	8.83
Fitchburg Gas & Electric	Mass.	1988	12	93	13	1	6.78	10.28
Massachusetts Electric Co.[a]	Mass.	1988	200	n.a.	n.a.	1	7.47	6.37
Average capacity-weighted price							5.62	6.21
Average uniform-weighted price							5.37	6.55
Standard deviation							(0.97)	(1.47)

Source: Cameron (1996, tables 1 and 2), and additional data provided by the author.

Note: Average contract prices represent annualized deflated average energy prices, normalized to 1991 dollars. Average contract prices assume a discount rate of 9.72 percent and depend on assumed fuel cost escalators and capacity utilization rates; for details, see Cameron (forthcoming, appendix A).

[a] Data for Massachusetts Electric Company's solicitation are based on only one publicly available contract; four contracts were awarded. Price data for the Virginia Electric & Power Company's 1986 solicitation are based on only seven contracts, totaling 700 MW. In addition to possible selection bias in the average contract prices for these solicitations, awarded contract average prices for these two solicitations are based on initial year capacity utilization rates, rather than those expected at the time of the solicitation. This nonsampling error accounts for the contract average prices exceeding the average reservation price in the data for these two solicitations.

constructed by the utility. This avoided cost determines a (publicly known) reservation price for new capacity. The prospective buyer then tenders a solicitation for a fixed amount of additional capacity and selects a winner through competitive bidding, negotiation with a selected pool of applicants, or a combination of the two.[18] The selection culminates in execution of a long-term power sales contract between the utility and the unregulated seller, subsequent construction of the seller's proposed generation facility, and operation of the facility and delivery of power to the host utility for the duration of the contract. The data in table 1 represent a total of sixty-five separate contracts competitively awarded by the indicated utilities.

For the sample of firms in table 1, entrants can consistently underprice the projects proposed by regulated incumbents for the addition of new capacity. On a capacity-adjusted basis, the average price of power from entrants is nearly 10 percent lower than that of incumbents. This mean 0.59 cent per KWh margin is quite substantial; for the average household (nationally), such a price change would correspond to a 7 percent reduction in its $827 annual bill absent any consumption response.[19] The average prices in table 1 are generally lower for solicitations bid in later years than in earlier ones, mirroring anecdotal evidence from the industry of continued technological progress and learning-by-doing among entrants.

Data such as those in table 1 have had a considerable influence on the level of enthusiasm exhibited by regulators toward proposals for power industry deregulation. The conclusion that entrants' lower average costs will lead to lower retail prices makes important assumptions about the behavior and contestability of these markets, however. In its traditional institutional environment a power plant is the quintessential example of a sunk cost: it is immobile, illiquid, and essentially cannot be converted to serve any purpose other than generating electricity at prices determined by regulatory authorities *ex post*. The perceived and real threat of disallowances from utility regulators (who cannot commit

18. Cameron (forthcoming) examines the efficacy of these forms of procurement. She finds that bidding results in significantly lower prices but, relative to more flexible forms of procurement involving negotiation, is associated with a higher ultimate incidence of seller default.

19. Calculated from EIA (1995a, tables 4 and 7).

beforehand to do otherwise) presents well-recognized disincentives for investment.

Outside the traditional utility-regulator procurement relationship, long-term contracting generally mitigates this holdup problem. The enforceability and assignability of long-term sales contracts between nonutility suppliers and utility buyers allow entrants to secure project financing (the typical mode of financing entry in this industry), since a creditor can step in and operate the facility in the event of seller default and collect expectation damages in the event of buyer default. As a result, the fixed costs of the physical capital incurred by the entrant subsequent to contracting are no longer sunk; the cost of exit is only the amount by which a revenue stream specified *a priori* is exceeded by a sequence of costs incurred *ex post*. Long-term bilateral contracts are a universal feature of sales from new entrants in power markets; durations of fifteen to thirty years are standard, with forty years not unheard of.[20]

In a fully deregulated power market the contractual opportunity set changes, but the effect still is the same. The availability of buyers willing to sign assignable long-term contracts allows potential entrants to lock in the revenues from entry relatively costlessly, which is to say, before having to incur the substantial expenses of acquiring the physical means of production. These are precisely the requisite conditions for a plausibly contestable market.[21] Despite the inherently sunk nature of investment in this industry, bilateral contracting can ameliorate the sunk-cost hazards of investment.

In a deregulated environment of the sort envisioned for California, this situation changes slightly, to one analogous to that faced by commodity producers with fixed costs of production. Here the relevant asset-specificity risks posed by sunk investments are not those of pure bilateral holdup, but the basic problem of spot price volatility: electricity is essentially nonstorable, the physical assets have no use other than producing power, and prices can be persistently bid down to a fraction of average costs if the market experiences excess capacity. As with other standardized commodity markets, however, a spot commodity

20. Comnes, Kahn, and Belden (1996, table 1).

21. The role of assignability is important here. It presupposes both the low switching costs and low product differentiation assumptions of the contestability literature. See Baumol, Panzar, and Willig (1988), or Gilbert (1989) and references therein.

market creates the basis for liquid forward markets, and these grease the wheels of entry.

Specifically, a smoothly functioning "power pool" should allow potential entrants to contract with buyers through long-term forward sales to distributors and consumers, and through standardized hedges against the spot price with financial intermediaries. Although forward sales of electric power are typically arranged before the fixed costs of entry are incurred, a robust spot market enhances the ability of entrants to securitize the investment hazards of entry. Provided that the particulars of deregulation do not raise the transaction costs of long-term contracting (for example, through a botched system of transmission network scheduling and delivery rights), such instruments can mitigate the sunk-cost impediments to entry in deregulated power generation markets.

The resulting implications for entry threats are profound.[22] Because of entrants' cost advantages relative to many incumbent electric utilities, amelioration of the sunk investment hazards of entry opens the door to a flood of potential entrants who can target areas with chronically high prices. Although the dynamics of short-run price competition may be quite complex, deregulation can be expected to drive the long-run price of power down to the average cost of *de novo* entry.[23]

Incumbents and Regulated Markets

The recently developed interest in deregulatory reform by policy makers in California and elsewhere has been shaped by simple "yardstick" comparisons of the extent to which average prices in particular states exceed national and neighboring states' counterparts. To be certain, the cost variation among vertically integrated electric utilities is

22. See Newbery (1995).

23. There is an emerging academic literature on producer pricing strategies in deregulated power markets, motivated principally by the 1990 privatization and reorganization of the British electric power industry. Green and Newbery (1992) and von der Fehr and Harbord (1993) analyze bidding strategies for spot (daily) power market auctions appropriate to the U.K. market, drawing on Klemperer and Meyer's (1989) supply function equilibria (SFE) concept. Wolfram (1995) and Wolak and Patrick (1996) present empirical studies of producer pricing behavior in the U.K. power pool, the former suggesting broad departures in producers' pricing behavior from the predictions of the SFE models. Precisely how short-run price and product competition among incumbents will play out in deregulated markets remains an open question.

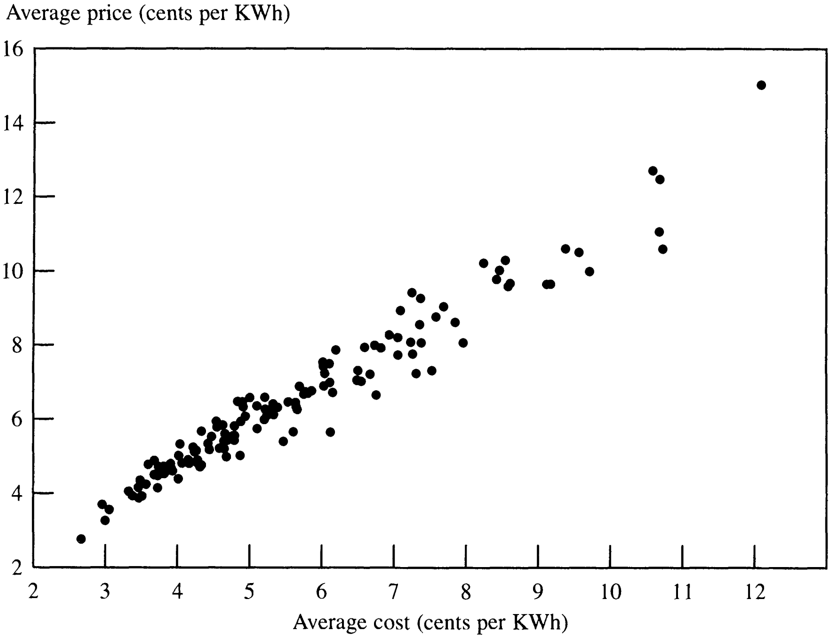
enormous; given the qualitatively similar average-cost pricing rules employed by state regulators, the same holds true for prices. The striking pattern that characterizes the industry's cost structure is illustrated in figure 1, which presents average cost and price data for a sample of 136 investor-owned vertically integrated electric utilities.[24] The range of firm-level average costs among incumbents spans a factor of five, an enormous difference for a homogeneous product. The sustainability of this industry cost structure in a competitive environment lies at the heart of debates over electricity deregulation.

How the industry came to arrive in this remarkable situation is a question that could easily fill another paper, or possibly several.[25] Three contributing factors are readily identified, however. First, much of the cost variation reflects the industry's expensive foray into nuclear power, which different firms participated in to widely different degrees. Overly optimistic forecasts of electricity demand growth, in conjunction with overly pessimistic forecasts of fossil fuel prices, led many utilities to pursue nuclear power projects during the 1970s. Neither the demand nor the relative fuel prices materialized as expected. Pervasive construction difficulties, however, combined with tighter safety standards by the Nuclear Regulatory Commission in the wake of the 1979 Three Mile Island accident, drove up nuclear plant capital costs dramatically. Capital costs for completed nuclear plants during the 1980s ranged from \$2,000 to \$4,000 per kilowatt of capacity; by comparison, the costs of base-load coal facilities built during the mid-1980s ranged from \$500 to \$900 per kilowatt, and capacity can be procured under long-term contract from independent power producers today at rental rates less

24. The electric utility industry is composed of three classes of producers: investor-owned utilities, publicly owned utilities (federal, state, and municipal power agencies), and rural electric cooperatives. The sample in figure 1 is a near census of the vertically integrated utilities in the former class, omitting a set of investor-owned firms accounting for 3.1 percent of retail sales that are either not vertically integrated or for which data were not available. (Of the 179 firms for which complete data were available, 136 firms operate generation, transmission, and distribution facilities and are considered vertically integrated.) Overall, investor-owned utilities account for 76 percent of retail sales nationally; publicly owned utilities, which are not subject to state-level rate regulation, account for two-thirds of the remainder; and rural cooperatives, the balance.

25. Berndt, Epstein, and Doane (1996) provide a statistical decomposition of numerous production and demand factors that jointly explain interutility variation in average prices.

Figure 1. Average Cost and Average Price of U.S. Investor-Owned Vertically Integrated Electric Utilities



Source: FERC (1994, form 1, schedules 1, 3, 7, 9, and 10).
Note: Average price includes electricity sales to ultimate consumers and sales for resale, excluding wholesale wheeling transactions. Average costs are computed from total electric operating expenses (including depreciation) before income taxes and charges for deferred income tax liabilities, plus electric utility net interest charges. Data for combination electric and gas utilities and firms with nonutility operations represent electric utility operating expenses per the FERC Uniform System of Accounts.

than \$200 per kilowatt-year.[26] Needless to say, no new nuclear plants have been ordered by a U.S. utility in more than a decade. The sunk costs of these plants are far from paid, however, since the standard straight-line depreciation schedules imposed by regulatory accounting standards force utilities to spread the recovery of their past capital expenditures over thirty years or more. Much of the far-right scatter in figure 1 is attributable to the impact of nuclear power projects.[27]

Second, there is the legacy of early fiascoes in implementing the Public Utilities Regulatory Policy Act of 1978. This legislation saddled

26. Nuclear and coal plant capital costs are from EIA (1991, tables 16 and 12); independent power prices are from Comnes, Kahn, and Belden (1996, table 3).

27. A table listing the data in figure 1 with the corresponding corporate affiliation is available from the author. The notable outlier at the upper right is the Long Island Lighting Company.

many utilities with long-term obligations to buy now-overpriced power from independent producers. Regulators, particularly in California, New York, Massachusetts, and Texas, moved aggressively during the early 1980s to require utilities to purchase power from any qualified independent supplier. The prices stipulated by regulators to be paid to independent producers were commonly derived from forecasts of utility opportunity costs based on wildly overestimated fossil fuel prices; contracts based on forecasts of oil prices reaching $100 per barrel or more before 1989 were not uncommon.[28] Moreover, the standard contracts imposed by regulators provided remarkably long terms and limited flexibility to adjust prices to changing market conditions over time; as high fuel prices failed to materialize and alternative generation technologies became increasingly attractive, utilities found themselves burdened with billions of dollars in above-market power purchase contracts. Many of these contracts will continue until well into the next decade.

Third, the data in figure 1 reflect to some extent the variation attributable to exogenous differences in regional factor prices and resource endowments. Exogenous interfirm variation in average costs arises in as-delivered fuel prices, hydro power availability, load factors (average to peak demand ratios), transmission network costs, tax rates, and a variety of lesser expenses. The first two of these items account for the bulk of exogenous variation in utilities' costs, and readily explain 1 to 1.5 cents per KWh of the variation in average costs among the firms in figure 1.[29]

These observations carry several far-reaching implications. First, the explanations offered for the variation in firm-level costs suggest that such costs should be correlated among firms serving the same state. Given the substantively identical average-cost pricing policies employed by utility regulators throughout the United States, the same should also hold true for prices. These implications are borne out in the

28. California Public Utilities Commission (1993).

29. As-delivered prices for fuel, a factor typically accounting for more than 25 percent of utility operating expenses (including depreciation), differ by a factor of about 2 nationally ($1.50 to $3 per million Btu; see Comnes, Belden, and Kahn, 1995, table D-1), explaining at best 1.5 cents per KWh of the variation in firm-level average costs. Fuel expenditures per KWh sold, which incorporates the significant geographic variation in hydroelectric power availability, ranges from 0.5 to 3 cents per KWh for 90 percent of the firms in the sample in figure 1.

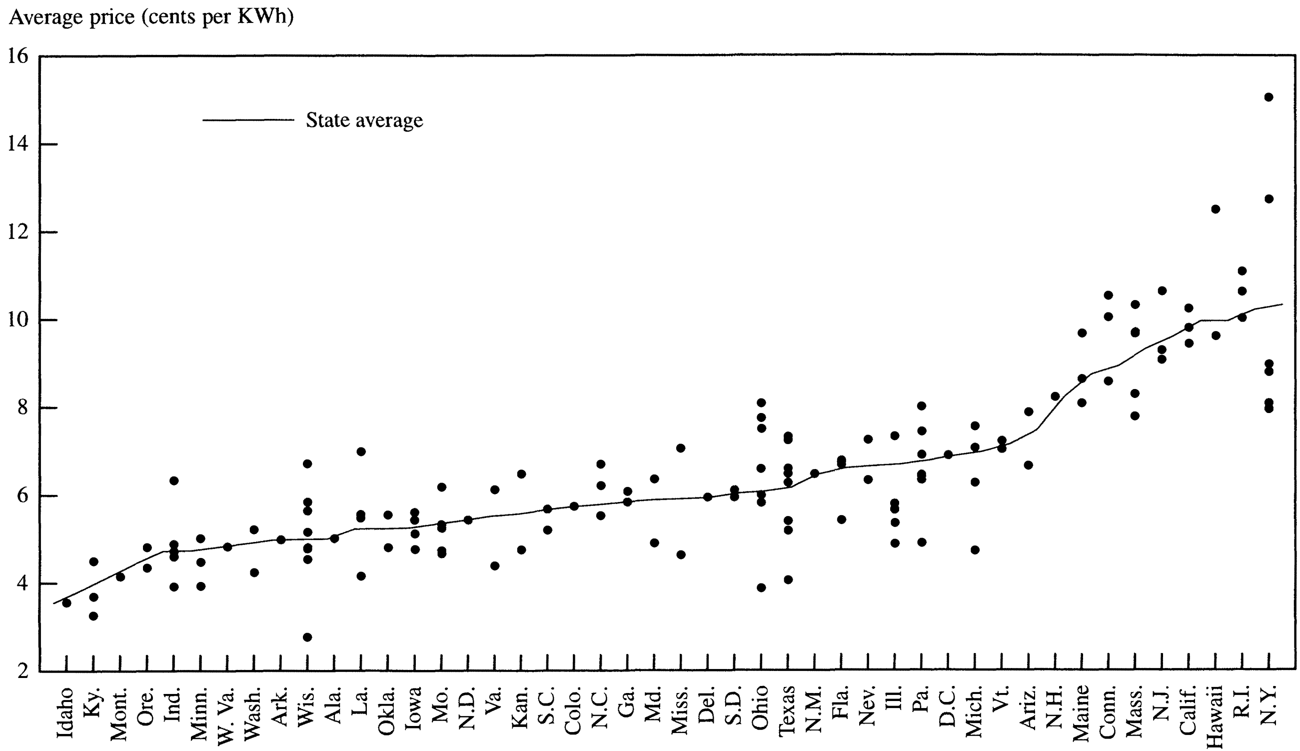
data. Figure 2 presents the average prices for the same sample of firms as in figure 1, sorted by state. This cut at the data reveals substantial variation in state-level average prices, and a clear pattern of within-state variation relative to the total variation evident in the data. From this pattern of price heterogeneity, one might naturally infer that states, as the political unit of analysis, may ascribe rather different importance to the value of utility regulatory reform. Not surprisingly, there is a clear association between these average prices and the states undertaking deregulatory efforts: California, Massachusetts, New York, and New Hampshire are among the highest-price states in the country.

The second implication is that the heterogeneity evident in the data does not provide a particularly accurate indication of the potential gains, from a social perspective, from price and entry deregulation. Much of the costs constituting the average cost data are sunk, and the high-cost firms in figure 1 differ from the average because they are characteristically saddled with above-market long-term power procurement contracts with independent suppliers or with enormous debt obligations associated with sunk investments in nuclear power plants. Such attributes exacerbate the pervasive wedge between marginal and average costs in the power generation industry. From an economic efficiency perspective, the comparison of interest is whether the average costs of potential entrants are below the marginal costs of incumbents; these data do not inform this comparison. Without further information, it would be a mistake to infer from the heterogeneity in figure 1 much about the merits of deregulation, one way or the other.[30]

From a political perspective, however, such marginal and average cost comparisons are all but irrelevant. What matters is whether the prices under the status quo exceed those that are expected to prevail with regulatory reforms to admit competitive entry. This is the price

30. In addition, it would be tenuous to argue, on the basis of these (or any similar) data, that the industry's cost variation would not have been exhibited in the absence of regulation. From a statistical perspective, there is no sense in which one can view the data in figures 1 and 2 as the outcome of a "natural experiment": the practice of state-level electric utility regulation is qualitatively similar throughout the United States. Not only has there been no appropriate control, there has been essentially no covariation. Although much of the high costs of utilities in California, New York, Massachusetts, and Texas are part of the legacy of poorly designed regulatory mandates pursuant to PURPA (which utilities opposed at the time), it is also the case that the majority of state regulators, facing the same federal legislation, managed to avoid such fiascoes.

Figure 2. Average Price of Investor-Owned Vertically Integrated Electric Utilities, by State



Source: FERC (1994, form 1, schedule 9).
Note: Average price includes electricity sales to ultimate consumers and sales for resale, excluding wholesale wheeling transactions.

gap problem facing regulators. The sunk nature of incumbents' investments in long-lived assets and regulators' imposition of equally long-lived depreciation schedules have left both regulators and the regulated with precious little wiggle room to match prices to market conditions. Despite the steep declines in the capital cost of new plant in recent years, without changes in the regulatory status quo the effects of these declining prices are unlikely to reach consumers.

How big is the gap between prices under the regulatory status quo and those expected under market conditions? Here the specific industrial organization proposed for restructured power markets comes into play. The regulatory reform proposals to implement competitive entry essentially apply only to price and entry deregulation of the generation segment of production. Power transmission, distribution, and a host of additional functions currently provided by integrated utilities (energy efficiency programs, low-income subsidy programs, and so on) are expected to continue to be provided by local franchise monopolies subject to some variation of average-cost price regulation. Thus, to characterize the potential price gap facing incumbents and their regulators, one needs to unbundle the costs of incumbents into those for the commodity potentially subject to competition and those for delivery and related services that are not.

Unbundling Incumbents' Costs

As a benchmark of how the cost of providing power under the existing regulatory system breaks down into the constituent functions of today's vertically integrated producers, table 2 presents industry-wide average costs and (approximate) implicit prices by vertical function. It is based on accounting data for the 179 largest investor-owned electric utilities.[31] According to the data, generation directly accounts for 63 percent of total costs, breaking down into operating costs (31 percent), depreciation and interest (13 percent), and power purchased from others (19 percent). These are the costs potentially subject to competition under the standard prescription for the reorganization of this industry

31. These 179 firms represent nearly the complete population of investor-owned electric utilities in the United States, omitting a set of firms for which data were not available that account for less that 0.04 percent of total investor-owned utility retail sales. See note 24 for additional discussion of sampling and the different populations of firms in the industry.

Table 2. Total and Average Costs of the 179 Largest Investor-Owned Electric Utilities, by Function

Function	*Total expense (mill. 1994 $)*	*Average cost (¢ per KWh)*	*Percentage of average cost*	*Percentage of average price*
Power production				
Power generation	47,665	1.7	31.1	26.6
Power purchases	29,213	1.1	19.0	16.3
Total	**76,879**	**2.8**	**50.1**	**42.9**
Transmission	**2,069**	**0.1**	**1.3**	**1.2**
Distribution	**5,933**	**0.2**	**3.9**	**3.3**
Depreciation and interest				
Production plant	19,169	0.7	12.5	10.7
Transmission plant	3,700	0.1	2.4	2.1
Distribution plant	8,920	0.3	5.8	5.0
General plant	1,394	0.1	0.9	0.8
Amortization	1,241	0.0	0.8	0.7
Total	**34,424**	**1.3**	**22.4**	**19.2**
Other operating expenses				
Customer accounts and service	5,502	0.2	3.6	3.1
Sales and marketing	232	0.0	0.2	0.1
Administrative and general	14,515	0.5	9.5	8.1
Taxes other than income taxes	13,275	0.5	8.6	7.4
Miscellaneous	677	0.0	0.4	0.4
Total	**34,202**	**1.2**	**22.3**	**19.1**
Total expenses (before income taxes)	**153,507**	**5.6**	**100.0**	**85.6**
Electric utility income				
Income taxes	10,901	0.4		6.1
Net income	14,899	0.5		8.3
Total	**25,800**	**0.9**		**14.4**
Total operating revenues	**179,307**	**6.5**		**100.0**

Source: EIA (1995b, tables 6, 11, 15, and 27).

Note: Totals may not equal sum of components because of independent rounding. Data are for the 179 investor-owned electric utilities classified as Class A (''Major'') Electric Utilities by the FERC. For combined electric and gas utilities, data represent electric operating expenses, income, and revenues per the FERC Uniform System of Accounts. Allocation of total depreciation and net interest expenses among production, transmission, distribution, and general plant are approximate. Income taxes include net deferred income tax liability and investment tax credit adjustments.

by vertical unbundling. They represent an annual $113 million market, approximately, if these reforms are adopted nationally. In contrast, the ''wires'' side of the business is relatively small: transmission and distribution account for 13 percent of total costs, an average of 0.7 cent per KWh, which utilities are likely to face no significant incentives to reduce. How the balance of the industry's operating costs, averaging

1.2 cents per KWh, is likely to be affected by deregulatory reforms is more difficult to characterize. Some of these expenditures are ambiguously classified between the functions likely to be provided by regulated transmission and distribution companies and unregulated generation firms.[32]

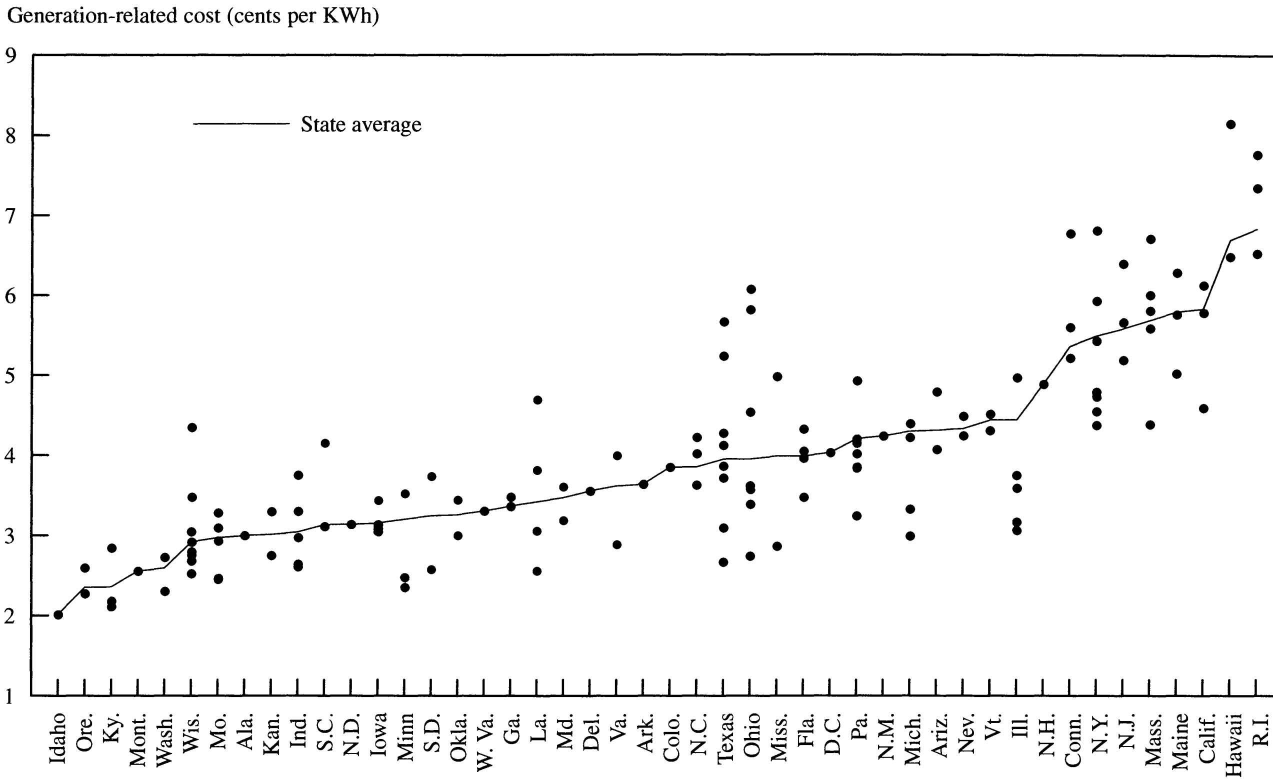
Although informative as an industry benchmark, the aggregate statistics in table 1 mask the heterogeneity in generation costs among incumbents. Figure 3 presents the results from unbundling the firm-level average costs of figure 1 for each of the 136 vertically integrated firms. The average generation-related costs shown for each firm are the sum of power production costs, purchased power expenses, generation plant depreciation charges, generation-related net interest expenses, and generation-related administrative operating expenses. The source data are the sample firms' regulatory accounting reports to the FERC (Form 1) for fiscal year 1994.

The problem that price and entry deregulation presents to certain incumbents is immediately evident in figure 3. Regulatory reforms to admit competitive entry in power generation will truncate this industry scatter from above, at a price equal to entrants' average costs. The bid prices and quantities in table 1 suggest that for those four states, relying on unregulated entry to determine the price of power may perform at least as well as continued administrative price adjudication by regulators. Figure 3 suggests that the same should hold in California, throughout New England, and in a number of other states whose firms lie farther to the right in the frequency distribution of industry prices.

Taking all of the data at face value, the heterogeneity evident in figure 3 casts doubt on whether this is a reasonable expectation for a fair number of firms in the states composing the lower tail of the price distribution. A comparison of figure 3 and table 1 does not present compelling *prima facie* evidence that entrants can be expected to profitably underprice incumbent utilities nationally. The average price from entrants in table 1 is 5.37 cents per KWh, while the average generation-

32. How such costs will be addressed in a deregulated environment depends on corporate restructuring and regulatory decisions that have not yet been made. Clearly, integrated utilities not subject to complete vertical divestiture (a politically dubious outcome in many states) would prefer to allocate as much of these costs as possible to the regulated side of their future activities, a time-honored practice pioneered by the Bell System and its unregulated manufacturing subsidiary, Western Electric. See, for example, Kellog, Throne, and Huber (1992, § 3.2.5).

Figure 3. Average Generation-Related Cost of Investor-Owned Vertically Integrated Electric Utilities, by State



Source: The average generation-related costs shown for each firm are the sum of power production costs, purchased power expenses, generation plant depreciation charges, generation-related net interest expenses, and generation-related administrative operating expenses. The source data are the sample firms' accounting reports to the FERC (Form 1) for fiscal year 1994.

related cost for the sample of utilities in table 2 is 3.5 cents per KWh. This is an enormously significant difference, in an economic (as opposed to statistical) sense; although the dispersion in incumbents' costs is large, only twenty-three firms in figure 3 have average generation-related costs that exceed the 5.37 cents per KWh average for the sample contracts in table 1.[33]

After unbundling incumbents' costs to ascertain the costs potentially subject to competition from new entrants, it is possible to quantify the price gap problem facing incumbents and their regulators. Some estimates of the magnitude of the price gap for different states are provided in table 3. The price gap is computed as

$$\textit{price gap} = P_{total} - [(P_{total} - P_{gen}) + \min(P_{gen}, P_{entry\ gen}),$$

where P_{total} equals incumbent's average price from figure 1, P_{gen} equals incumbent's implicit generation price, and $P_{entry\ gen}$ equals an entry-inducing generation price. The implicit generation price, P_{gen}, is a firm-specific mark-up on the average generation related-costs in figure 3 calculated by allocating firm-level net revenue to generation and non-generation functions proportionate to their respective shares of average total costs.[34] Results for a range of entry prices are shown to indicate the sensitivity of the results to the deregulated equilibrium price and because entry costs are widely believed to have fallen by more than 1 cent per KWh since the late 1980s, when the data in table 1 were realized.[35] The price gap figures shown in table 3 for each state represent the quantity-weighted average price gap calculated individually for the firms operating in that state.

33. It should be noted, however, that table 1 presents entrants' prices, not costs, and these prices are likely to reflect a positive economic profit by entrants. For the solicitations shown in table 1, the terms of the winning bids were subject to *ex post* public revelation, potentially biasing the cost revelation prediction of one-shot auction theory. In addition, many contracts were negotiated with only a partial weight on price, and utilities and their regulators have had to struggle with the mundane matters of logistically efficient procurement procedures. As a result, a direct comparison of figure 3 and table 1 should yield an underestimate of the extent to which nonutility entrants can profitably underprice incumbents.

34. This net revenue allocation rule is essentially arbitrary; separate demand functions for the generation and nongeneration services currently provided by incumbents are not available.

35. Claims of ''green-field'' entry at average costs in the 3 to 4 cents per KWh range abound within the industry and the trade press. See, for example, Hirst and Baxter (1995). Substantiating nonprospective data are generally considered proprietary.

Table 3. Estimates of the Price Gap between Entrants and Incumbent Utilities, by State
1994 cents per KWh

	Entry-inducing price			
State	*5.0*	*4.5*	*4.0*	*3.5*
Hawaii	2.5	3.0	3.5	4.0
Calif.	2.0	2.5	3.0	3.5
R.I.	2.0	2.5	3.0	3.5
N.J.	1.7	2.2	2.7	3.2
Maine	1.3	1.8	2.3	2.8
N.Y.	1.3	1.8	2.3	2.8
Conn.	1.2	1.7	2.2	2.7
Mass.	1.3	1.7	2.1	2.5
N.H.	0.7	1.2	1.7	2.2
Nev.	0.1	0.6	1.1	1.6
Ill.	0.4	0.7	1.2	1.6
Mich.	0.3	0.6	1.1	1.6
Ariz.	0.1	0.5	1.0	1.5
Pa.	0.3	0.6	1.0	1.5
N.M.	—	0.5	1.0	1.5
D.C.	—	0.4	0.9	1.4
Vt.	—	0.3	0.8	1.3
Texas	0.1	0.4	0.8	1.3
Ohio	0.4	0.6	0.9	1.3
N.C.	—	0.2	0.7	1.2
Fla.	—	0.2	0.6	1.1
Miss.	0.2	0.5	0.8	1.0
Del.	—	—	0.3	0.8
Colo.	—	—	0.3	0.8
Ga.	—	—	0.3	0.8

(continued)

For a number of states, status quo regulatory practice is no longer serving to maintain consumer prices below the level that would obtain in the absence of statutory entry barriers. Moreover, there is a clear correspondence between the magnitude of the price gap and states' deregulatory activity. Although California and the New England states top the list in table 3, the states that have decided against moving forward with regulatory reforms—Washington, South Carolina, and North Carolina—barely make the price gap list (except for North Carolina in a low-entry-price scenario). Of course, these price data obscure large differences in expenditure impacts because of demand variation across states, and presumably a better metric than the price gap is the

Table 3. (Continued)
1994 cents per KWh

	Entry-inducing price			
State	*5.0*	*4.5*	*4.0*	*3.5*
Md.	—	—	0.3	0.8
Va.	—	0.1	0.4	0.7
La.	—	0.1	0.3	0.6
S.C.	—	—	0.1	0.6
S.D.	—	—	0.2	0.5
Kan.	—	—	0.2	0.4
Ark.	—	—	—	0.4
Ind.	—	0.1	0.1	0.4
Mo.	—	—	—	0.3
Okla.	—	—	—	0.3
Ala.	—	—	—	0.2
W.Va.	—	—	—	0.2
Iowa	—	—	—	0.2
Minn.	—	—	—	0.1
N.D.	—	—	—	0.1
Wis.	—	—	—	0.1
Idaho	—	—	—	—
Ky.	—	—	—	—
Mont.	—	—	—	—
Ore.	—	—	—	—
Wash.	—	—	—	—

Source: Author's calculations (see text).

opportunity cost that it generates. Estimates of the opportunity costs resulting from the price gap are provided in the next section. Nevertheless, the heterogeneity in prices and costs evident in the data strongly suggests that the aggregate consumer surplus from price and entry deregulation nationally would be asymmetrically distributed across the states. Inasmuch as the relevant deregulation decisionmaking units are the individual states, the interesting question before us is whether the states served by relatively low-cost firms will bother to entertain significant regulatory reforms at all.

Regulatory Adjustment to the Price Gap

The previous evidence suggests a straightforward explanation for the decisions of regulators in certain states to pursue price and entry deregulation of electricity markets. Changes in the economics of power generation have undercut the cost structure of incumbents to the point where the costs of small-scale entry into the power generation business are well below the average costs of many incumbent utilities. The result is a substantial increase in the opportunity cost of statutory entry barriers and political pressure on regulators to close the price gap. In high-cost states the magnitude of the price gap suggests fairly strong incentives for consumers to press for regulatory changes, and deregulatory reforms are the natural result.

This simple political economy story has two shortcomings, however. First, it provides a rather nebulous specification of the mechanism by which the price gap yields deregulatory outcomes as an adjustment response. Second, it does not address the regulatory treatment of incumbents' sunk investments in assets rendered unprofitable by these regulatory policy changes. I attempt to redress the first of these two shortcomings in this section; the issues posed by the stranded costs problem are discussed later in the paper.

The thesis to be advanced is that, at the state level, the political incentives of policymakers to accommodate deregulation are heavily influenced by whether the price of power under traditional cost-of-service regulation exceeds the price likely to prevail in the absence of price and entry regulation. Pressure for regulatory reform is determined by whether this price gap is positive and, if so, by the magnitude of the implied transfers. Institutional considerations suggest that the incentive to accommodate deregulation as a regulatory response is not immediately increasing for small excess prices, however. Specifically, if the expected price that would prevail in the absence of regulation merely dips below the prices currently imposed by regulators, but not below average (accounting) costs for the regulated, the obvious regulatory response, if any, is simply to torque down regulated prices and thereby eliminate consumers' incentives to push for deregulatory reforms. Given six decades of regulatory practice and institutional memory, it would be tenuous to argue that massive regulatory restructuring would be a more likely response to such pressures than this type of nonstructural regulatory price adjustment.

This is the problem that confronts "consumer interest" political economy explanations for the deregulatory reforms unfolding in this industry. From the perspective of the behavior of regulators, it should be less costly to ameliorate pressure from politically vocal consumer groups through nonstructural price adjustments than with dramatic regulatory reforms of the sort under way in California. The resolution of this conundrum, however, lies not in seeking an objective function for regulators that minimizes the weight given to political pressure from consumers; this is throwing the baby out with the bath water. Rather, to observe deregulation, the magnitude of the price gap must be sufficiently large that the pressure to bring existing prices into line with the market equilibrium cannot be accommodated within the institutional constraints of the regulatory process.

What administrative regulatory mechanisms cannot accommodate is a downward price adjustment of sufficient magnitude to unequivocally deprive the regulated of a "fair rate of return" on their prudently incurred assets. Although regulators generally have wide latitude in translating this institutional obligation into hard numbers, this flexibility is ultimately bounded by prices equivalent to the average (regulatory accounting) costs of the regulated—in other words, the costs of assets and services previously determined to be prudent and necessary. Regulators can (and do) reset prices to yield a zero expected economic profit to the regulated (and therefore a zero expected return to shareholders relative to similarly risky market opportunities); what would be beyond the pale would be for regulators to set prices so low as to yield negative expected accounting profits—implying a negative expected (*not* excess) return to the owners of the firm.

This line of argument suggests comparing the opportunity cost of the price gap to what can be accommodated within the existing regulatory process. Presumably, the incentive for consumers to push for regulatory change is proportional to what they expect to gain from doing so. If the power prices expected to prevail in the absence of entry regulation exceed regulated firms' generation costs, then whatever interest consumers bring to bear for regulatory change may be placated by regulators through price adjustments rather than institutional reforms. But if the prices expected to be offered by entrants are below regulated firms' generation costs, then it cannot, and it is the incentive to influence the regulatory process generated by this excess forgone surplus that should induce deregulation as a regulatory response. Alternatively stated, the opportunity cost to consumers of not realizing price and entry deregulation is only the amount by which the total consumer surplus (from reducing the existing regulated price to that expected to prevail in a deregulated market equilibrium) exceeds the surplus that could be achieved within the existing structure of regulation.

This opportunity cost (or what I will call "adjusted consumer surplus") defines the incentive for consumers to push for regulatory changes that are beyond what can be accommodated within the existing structure of regulation. As an empirical matter, this means comparing firm-level generation-related regulatory accounting costs with plausible values of power prices likely to prevail in a deregulated market. The arguments of the previous section suggest that prices in a deregulated market can be bounded above by the prices that would provide a zero economic return to entrants. Such zero-profit prices, in turn, are bounded above by the prices evidenced for the sample of competitive entrants in table 1. Thus, the analysis to be performed here is analogous to examining the frequency distribution of firm-level generation costs for the industry as a whole, and assessing the impact on consumer expenditures of truncating it from above at plausible values for entry-inducing prices. In states whose firms lie in a position of the distribution that is truncated by expected entry-inducing prices, the pressure for entry deregulation should generate a positive deregulatory response.

As stated, this is less than a sharp test, given the within-state variation in average generation costs across firms. Moreover, there are undoubtedly some latent costs of restructuring the regulatory process that are relevant to participants but not observed here; such transaction costs could play a role in deterring deregulatory outcomes, although probably in the marginal states. As such, the opportunity cost estimates provided in table 5 should not be considered as sufficient statistics for deregulatory outcomes. Nevertheless, these opportunity costs should be broadly informative in identifying the incentive for consumers in different states to pursue deregulation, and perhaps the relative speed and earnestness with which reforms take hold in different states.

Table 4 presents estimates of the adjusted consumer surplus (nationally) that result from truncating the distribution of firm-level generation costs at some plausible values of entry-inducing prices, using various price elasticities available in the literature.[36] Methodologically, the ex-

36. There is an extensive econometrics literature on electricity demand forecasting and elasticity estimation. In particular, see Moroney (1984) and Nelson and Peck (1985).

Table 4. Adjusted Consumer Surplus Estimates
1994 dollars, in billions

Entry-inducing price (cents per KWh)	*Long-run price elasticity*		
	−0.4[a]	*−0.8*[b]	*−1.8*[c]
5.0	3.9	4.0	4.3
4.5	7.1	7.4	8.1
4.0	11.8	12.4	14.0
3.5	19.5	20.7	23.6

Source: Author's calculations (see text).
[a]Nelson and Peck (1985, p. 183).
[b]Taylor, Blattenberger, and Rennhack (1984, table 6).
[c]Jorgensen and Stoker (1984, table 2).

ercise here assumes that the new bundled-service price that may be charged by each incumbent firm in figure 1 is equal to an entry-inducing generation price indicated in table 4, plus the amount by which the incumbent utility's firm-level average price exceeds its generation-related average cost. In essence, this assumes that incumbents face a contestable generation market but that consumers face unchanged prices for the gamut of transmission, distribution, and other nonderegulated monopoly services provided by their local utility. The resulting maximal bundled-service price presents a binding constraint for only a subset of the incumbent firms, those whose average generation cost in figure 3 exceeds the indicated entry price in table 4. This exercise treats as unchanged the prices of the incumbents for which this constraint is nonbinding.

Table 4 may be interpreted as a conservative measure of the aggregate annual consumer surplus that would result in long-run equilibrium from a contestable power generation market at the indicated prices.[37] It is ''adjusted'' in the sense that it is based on the costs, rather than the price, of generation by incumbent regulated utilities. The ultimate consumer surplus from price and entry deregulation of electricity markets is on the order of billions, or perhaps tens of billions, of dollars per year. The surplus is highly variable with the assumed price that would

This literature presents widely varying long-run elasticity estimates, ranging from −0.4 to −2.0, depending on the model, data types, incorporation of appliance stock turnover, and sampling frequency used.

37. These are downwardly biased consumer surplus estimates for two reasons. First, they are based on the costs, rather than the price, of generation under the regulatory status quo. Second, they exclude the surplus accruing from regulatory price reductions where the entry-inducing price is not below incumbents' costs.

Table 5. Adjusted Consumer Surplus Estimates, by State
1994 dollars, in millions; unit price elasticity

	Entry-inducing price (cents per KWh)			
State	*5.0*	*4.5*	*4.0*	*3.5*
Calif.	1,591	2,531	3,606	4,755
N.Y.	904	1,510	2,295	3,166
N.J.	427	817	1,237	1,688
Ill.	—	420	908	1,459
Texas	70	149	443	1,412
Pa.	—	199	558	1,275
Ohio	306	503	850	1,255
Conn.	133	328	540	767
Mich.	—	—	269	725
Mass.	236	370	534	715
Fla.	—	—	71	704
N.C.	—	—	106	464
Maine	111	188	271	359
Va.	—	—	—	349
Hawaii	148	198	251	306
Ariz.	—	30	102	272
R.I.	136	179	224	271
Miss.	—	61	130	206
La.	—	11	42	175
N.H.	—	45	107	175

(continued)

induce entry of new power producers, a phenomenon that may explain the widely varying national stranded-costs estimates reported in various forums. Effects of this magnitude, however, constitute a considerable dent in the $159 billion in annual electricity expenditures of the investor-owned utility industry's 87 million retail customers. Holding constant current consumption patterns, for the average household (nationally) the $12.4 billion figure in table 4 corresponds to a $65 reduction in its annual $827 electricity bill.

The national average, however, is unrepresentative of the effect likely to occur in most states. Table 5 presents the state-by-state distribution in adjusted consumer surplus for each of the entry-inducing values shown in table 4. For each state in which there is a positive value in table 5, there is at least one utility whose average generation cost exceeds the indicated entry-inducing price. The value for each state is the incremental consumer surplus that would be realized by

Table 5. (Continued)
1994 dollars, in millions; unit price elasticity

	Entry-inducing price (cents per KWh)			
State	*5.0*	*4.5*	*4.0*	*3.5*
Nev.	—	—	65	171
D.C.	—	—	9	150
Colo.	—	—	—	86
N.M.	—	—	23	75
Vt.	—	1	27	60
Wis.	—	—	19	49
Ark.	—	—	—	45
Ind.	—	—	—	40
Md.	—	—	—	35
Del.	—	—	—	8
Minn.	—	—	—	7
S.D.	—	—	—	4
S.C.	—	—	1	2
Ala.	—	—	—	—
Ga.	—	—	—	—
Idaho	—	—	—	—
Iowa	—	—	—	—
Kan.	—	—	—	—
Ky.	—	—	—	—
Mo.	—	—	—	—
Mont.	—	—	—	—
N.D.	—	—	—	—
Okla.	—	—	—	—
Ore.	—	—	—	—
Wash.	—	—	—	—
W.Va.	—	—	—	—
Total	3,742	7,540	12,685	21,321

Source: Author's calculations (see text).

reducing firm-specific prices by the amount that (firm-specific) average generation costs exceed the entry-inducing price.

The results indicate that California is the state where consumers have the most incentive to press for regulatory change to admit competitive entry. The results are also remarkably strong for New York, New Jersey, and throughout New England. Taken as a whole, however, the data paint a picture of strikingly different incentives to pursue electric utility deregulation across different states.[38] Moreover, deregulation in

38. The range of plausible prices that might induce entry differ across regions.

the power industry is taking place in the states where consumers have the most to gain from deregulation. California, New York, Massachusetts, and New Hampshire are amply represented in each column of table 5. In contrast, the three examples of states not moving forward with deregulatory reforms—Washington, South Carolina, and North Carolina—show little incentive, except for North Carolina in a low-entry-price scenario.

Although this association of current deregulatory proceedings with the data in table 5 is what the previous arguments suggest, I should emphasize several cautionary notes regarding the interpretation of tables 4 and 5. First, the few states where I have observed an "outcome" on the matter of utility industry restructuring are a self-selected subsample of the population. The potential for sample selection bias should be kept in mind when interpreting these results, and their association with deregulatory reform activities. Although the results demonstrate a promising degree of association with the few deregulatory outcomes observed to date, a more careful basis for the arguments that motivated them, vis-à-vis existing theories of regulatory behavior, is warranted.

Second, the lower average costs for entrants relative to many regulated incumbents is not an indictment of the inefficiency of regulation per se. The average cost of new generation plant has been declining worldwide for more than a decade because of rapid technological progress among turbine manufacturers and increasing equipment standardization. Since generating assets are long lived, incumbents' portfolios of older assets reflect in part higher costs simply from investing at an earlier date. It is probable that even in the absence of deregulation, incumbents' average costs in real terms would decline over time as their capital stock turns over.

Third, and perhaps most importantly, it would be erroneous to interpret the values in tables 4 and 5 as "savings" in any social sense. Most of the high-cost incumbents' generation-related costs are sunk, and the costs of operating these assets henceforth is a fraction of the costs being

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Roughly speaking, regional differences in fuel prices can account for as much as 1 to 1.5 cents per KWh differences in average electricity output prices (see note 29). The high extremes are generally the Northeast, which is far from Canadian and U.S. natural gas fields; the low extremes are in the Pacific Northwest, which is endowed with ample hydroelectric resources.

carried on the books.[39] The sunk nature of incumbents' costs means that much, if not most, of the consumer surplus indicated by table 4 represents pure transfers, not gains in social welfare.[40] In particular, that the surplus estimates in table 4 increase little across the columns and substantially down the rows belies the fact that the dead-weight social gains from price reductions (the ''welfare triangle'' in Marshallian demand analysis) are quite small relative to the transfers.

Economic Theories of Regulation

Although perhaps a subtle point, the emphasis on transfers as the driving force behind changes in the regulatory landscape of the electricity industry is somewhat at odds with prevailing economic theories of regulation. As a general proposition, these theories suggest that alterations in the structure of regulation are best explained as the outcome of competition among interest groups for the benefits of regulatory action.[41] The argument offered above for regulatory adjustment to the price gap is similarly ensconced in interest group competition among consumer groups, potential entrants, and regulated incumbents. In this section I attempt to provide a more systematic integration of the preceding arguments into prevailing economic theories of regulation.

The positive correspondence of states' deregulatory activities with table 5 and the magnitude of the transfers indicated therein make a reasonably strong case that the changes under way in this industry are not being undertaken for the benefit of the regulated. This observation presents some difficulty for the Stiglerian economic theory of regulation, even with Peltzman's amendments after a decade of federal deregulatory activity.[42] Stigler observed that while the effects of regulation typically affect a few producers a great deal, consumers are a

39. Conditioning on the existing capital stock, the average power generation cost of 1.7 cents per KWh shown in table 2 provides a rough indication of the average marginal cost (across firms and output levels) for the investor-owned utility industry.

40. This important point underlies the much debated stranded-cost problem facing the utility industry.

41. See Peltzman (1989), Noll (1989), and Joskow and Rose (1989) for surveys of this literature.

42. Stigler (1971) and Peltzman (1989).

diffuse lot and are generally affected to a minor degree by regulatory policies in one particular market. Given the difficulties of marshaling the collective action of consumers and the informational advantages of producers vis-à-vis the legal and political machinery of regulatory policymaking, one should expect regulatory outcomes to reflect the superior ability of producers to perform in the market for regulatory influence.

Peltzman updated this and succeeding Chicagoan theories of regulation to accommodate regulatory exit. In Peltzman's updated interpretation, deregulation should occur when the gains to be distributed to producers from co-option of the regulatory process have withered to the point where this regulatory activity has lost its *raison d'être*. Stated as a sharper prediction, deregulation should occur when "the gap between the regulated equilibrium and the one plausibly characterizing deregulation of the industry narrows, so continued regulation becomes pointless."[43] The predictions of this "capture" theory of regulatory exit lie at odds with developments in the electric power industry, however. Specifically, the benefits to the regulated from maintaining status quo regulation are greatest in the states where electric utility deregulation is under way. Moreover, negligible price gaps characterize the states where such deregulatory efforts are absent.

At the opposite end of the regulatory spectrum from Stigler's "capture" theory is the pure "public interest" theory of regulation. It does not fare much better. Under this theory convergence of the regulated and unregulated market equilibria should produce deregulation because the apparatus of regulation no longer serves any purpose in rectifying requisite market failure and thus should wither away.[44] This "normative analysis as positive theory" of regulatory change is difficult to sustain on the basis of the evidence at hand.[45] Heterogeneity in deregulatory reform outcomes across states, under the public interest line of argument, must reflect some locally unique economic externality, barrier to entry, or other market failure. Electrical utility regulation is qualita-

43. Peltzman (1989, p. 20). Peltzman argues that this is empirically relevant because deregulation is to be expected when the wealth available for redistribution becomes too small to provide the requisite payoff to the regulated.

44. Ibid, p. 20.

45. The term "normative analysis as positive theory" as a description of the classical public interest theory of regulation is drawn from Joskow and Noll (1981).

tively similar throughout the United States, however, and it is difficult to argue that the worldwide technological progress in power generation that makes entry contestable in one region of the country would wholly fail to do so in another. In short, the pure public interest theory predicts that deregulatory reforms should unfold everywhere, or perhaps that comprehensive federal legislation with the same objective will be passed. While time will cast the deciding vote on the matter, the outspoken resistance of regulators in South Carolina and elsewhere provides suitable cause to be skeptical.

An alternative strand of the economic theory of regulation literature is more easily reconciled with the facts for the electricity industry as I have presented them: deregulation is occurring where the transfers inherent in the regulatory system have become so large (and so apparent) that the system is no longer (politically) tenable. This is, in essence, the argument advanced by Becker: the gross benefits to producers from maintaining the status quo are the same as those to consumers from altering it, less the deadweight social loss from maintaining prices above the efficient level.[46] Thus, the outcome in the states that have adopted reforms for the power industry reflects a recent change in the deadweight social losses from above-market prices, holding constant the relative efficiency of producers versus consumers in the market for regulatory influence.

While appealing, I believe such a theory is overly narrow. For example, it cannot explain the well-documented regulatory resistance to nominal price increases in the face of rising nominal costs of the regulated.[47] Rising costs reduce the deadweight social losses from the regulatory status quo, so producers should be able to exert more, not less, influence over regulated prices; from the perspective of Becker's theory, the "sticky" price phenomenon regularly observed in practice simply goes the wrong way. A second, and perhaps less consequential criticism, is that regulators do not openly state a willingness to peddle their authority to serve the highest bidder. Although words and deeds

46. See Becker (1983).

47. Joskow (1974, 1989). Lest I stand accused of leaving any oxen ungored, I should note that the Joskowian (1974) "quiet life" theory in which regulators avoid being the focus of political conflict among constituents does not fit observed behavior particularly well either, given the enormous transaction costs and political conflict in the states where regulators have formally entertained competitive reforms.

are obviously not the same, the great care that regulators take to couch any action as proceeding ''in the public interest'' suggests that there must be some political costs to be borne from doing otherwise. In particular, there must be private costs to regulators when it is publicly observed that transfers are being made to the regulated at the expense of consumers.

These observations suggest two possible interpretations: regulators prefer allocating rent to consumers rather than to producers (all other things being equal), or regulators perceive political costs to themselves associated with allocating rent to producers. This is not to say that regulators would not be responsive to the influence of competing interest groups. (Consider, for example, the rise of fuel cost adjustment mechanisms, energy efficiency programs, renewable resource procurement mandates, and low-income assistance subsidies that benefit particular constituencies in the utility regulatory arena at the expense of others.) But the relative efficiency with which organized interest groups exert such influence will be tempered by more than simply the ''welfare triangle'' forgone by consumers as a whole. Either of these two interpretations has the same important implication: regulators will be responsive to the size of the transfers accruing to producers from setting regulated prices above those that would prevail in a deregulated market equilibrium.

This offers some justification for the attention paid to the transfers calculated in the previous section and begins to offer a satisfying theory for the evolving pattern of regulatory change visiting the electric power industry. In equilibrium whatever efficiency advantages producers have over consumers in the market for regulatory influence should exactly offset the political costs of transferring rent to producers. In states where deregulation is taking place, the fundamental effect of technological change in the power industry has been to tip the balance of this political equilibrium in favor of consumers' interests, upsetting the alignment of consumers' incentives to press for changes in the regulatory status quo and producers' incentives to resist them. This imbalance would normally be restored by reducing prices within the existing regulatory mechanism of rate reviews, which offer a forum for consumers to press for changes that reflect falling prices outside the regulated environment. But when the prices expected to prevail outside that regulated environment have fallen sufficiently far, the institutional obligation to provide a fair rate of return to the regulated presents a binding constraint on downward price adjustments, and the regulatory system must accommodate structural changes.

This theory paints a clear picture of where one should look to see deregulatory reforms, given the heterogeneous set of prices and costs of incumbent electric utilities throughout the states. To alter the regulatory equilibrium, there must have been either a change in the relative efficiencies of producers and consumers in the market for political influence or a visible increase in the transfers received by the regulated relative to the outcome that would prevail under the deregulated market equilibrium. I eschew the explanation that there has been a significant shift in the technological frontiers of producers and consumers in the market for political influence; such markets have surely operated for as long as the power industry has been regulated, and it would be a tenuous endeavor at best to hang the dramatic changes under way in this industry on relative increases in the efficiency of lawyers, lobbyists, and the apparatus of advocacy. Rather, what has changed are the implicit transfers to producers, and to the extent that this increased opportunity cost to consumers cannot be accommodated within the regulatory system, reform is the natural outcome.

By this line of argument, the data in table 5 represent the incentives to pursue structural regulatory change and to bring prices into line with a deregulated market equilibrium. The correspondence of the results with the states where deregulation is currently under way is comforting, but the more important implication is that these states are where one should expect to see deregulation in the future. Although the prices and costs of the regulated utilities in states such as California and New York are high enough to lead to deregulatory reforms, states such as, say, Idaho and Washington have average prices so low that, unless entry becomes profitable at prices well below those considered in this paper, there is simply insufficient incentive for policymakers to contemplate radical reforms.

Of course, time will perform the acid test of validating the analysis offered here. But the data are sufficiently compelling that, despite the omitted details of individual states' regulatory politics, widespread adoption of California-style deregulatory reforms in the near future is unlikely. By the politically relevant metric of the price gap, regulation in many states has worked fairly well.

The Stranded Cost Problem

The billions of dollars in potential gains to consumers in tables 4 and 5 have a flip side: billions of dollars in losses to utilities. These losses represent more than just forgone profits; to a large degree, utility investments in generation resources constitute sunk assets whose costs would be unrecoverable under a shift to "market" pricing of electric power. This stranded cost problem is by far the most controversial aspect of regulatory reform in the electric power industry.

In large part, the overriding attention paid to stranded costs in the regulatory arena stems from the magnitude of the problem. Estimates of the stranded costs facing the investor-owned electric utility industry nationally vary from tens of billions of dollars to more than $200 billion, and utility-provided estimates often reach $300 billion.[48] These figures nominally represent the present value of the fixed, nonmitigable expenses of investor-owned electric utilities that are beyond what could be recovered from expected revenues with retail competition in electricity markets. Stated in other words, these are estimates of the write-offs that utilities would face if they had to sell all of their power at the prices expected to prevail in deregulated power markets and marked all of their assets to market value. Figures at the high end stretch credulity; the total book value of production plant industry-wide is only $298 billion, and total industry equity is approximately $165 billion.[49] Perhaps the most reliable estimate, and probably the most widely cited, is from a 1995 study by Moody's Investor's Service that pegged the stranded costs of U.S. electric utilities at $135 billion.[50] Not surprisingly, the Moody's study noted that stranded cost exposure is concentrated primarily among utilities in the Northeast and California.

The stranded cost problem raises several economic issues. Foremost among them is whether consumers should continue to incur the economic costs of utilities' past investments in the machinery of production

48. See Baumol and Sidak (1995, p. 99) and references therein.

49. EIA (1995b, table 28); Moody's Investor's Service (1995).

50. The wide variation in estimates of stranded costs reported in various forums may be partly explained by the sensitivity of market revenue estimates to assumed entry-inducing prices, as evidenced in table 4. The Moody's Investor's Service (1995) study used market prices comparable to the lowest entry-inducing prices in tables 4 and 5. It reported a range of possible total stranded costs for U.S. investor-owned utilities of $50 billion to $300 billion, depending on market price assumptions.

when lower cost alternatives are available. To date, the answer of regulators has been yes. Regulators in California, Massachusetts, and elsewhere have endorsed the idea of imposing "competition transition charges" to ease utilities' transition to a new market equilibrium. Specifically, while power markets would be open to competitive entry in power production (and marketing) beginning as early as 1998, new charges would be levied on the transmission and distribution segments in order to maintain near-current retail prices for the duration of an extended market transition period. These market transition mechanisms are singular in purpose, designed to pay off the outstanding costs of utilities' prior investments in power production resources that would otherwise be unrecoverable with policy changes to admit competitive entry.

There are several good reasons for these stranded-cost recovery mechanisms, based on both equity and efficiency grounds. The standard argument is that utility investments historically constituted part of a "regulatory compact" between utilities and their regulators. Utility investors committed their capital, and utilities undertook large investments with limitations on allowable rates of return, in exchange for limited risk that these returns would deviate from what was expected *ex ante*. Regulatory decisions to open power markets to competitive entry in the present circumstances constitute a violation of this long-standing "compact," punishing investors who, on the basis of the previous sixty years of regulatory practice, had no reason to incorporate into securities prices the risk to which their investments will now be exposed.

These arguments inescapably involve basic issues of equity, and they have been pursued at length by Baumol and Sidak.[51] There are also obvious dynamic efficiency issues raised by policy shifts that are viewed as reneging on an implicit contract. Given the sunk nature of utilities' past investments, deregulation presents a classic "holdup" problem of the sort examined in the literature on asset-specificity and transaction costs.[52] To the extent that financial markets perceive regime shifts as more likely to occur in the future than they have in the past, regulators may needlessly induce capital scarcity, distorting investment and raising the price of capital for all firms operating in the industry.

51. Baumol and Sidak (1995).
52. See, for example, Williamson (1985).

Whether such considerations played a decisive role in regulators' decisions in California and elsewhere to allow utilities to recover their stranded costs is unclear. The more pragmatic view is that the stranded-cost recovery policy was endorsed to avoid widespread credit downgrades and debt default on the part of the regulated, which would certainly impose political costs on their regulators. Nevertheless, the decisions of regulators to impose extended market transition periods does present a behavioral puzzle. Stranded cost recovery for utilities necessarily means that the prices facing consumers will change little, if at all, until well into the next decade. Moreover, the use of ongoing, rather than up-front, stranded-cost assessments has adverse feedback effects on future market behavior. In particular, adjusting stranded asset payoffs in light of market revenues actually received distorts the pricing incentives of newly deregulated incumbents and, for at least the duration of the payoffs, can reduce utility generation subsidiaries' costs of successfully deterring entry. The net effect is that regulators' policies in opening power markets to entry hold little promise for entrants for the duration of the stranded-cost recovery period, which is likely to be many years.

Thus, the regulatory treatment of the stranded cost problem presents a loose end for the positive theory of regulatory reform. Why have regulators, political actors with generally short official tenures, initiated complex and costly institutional reforms that over the next several years apparently benefit no one? This is perhaps the ultimate puzzle of the industry's current power struggles. I offer two explanations.

The first is that when the deregulatory process began in 1994 in California, the final decision on stranded costs was not a foregone conclusion. To some degree, the initial California proposal was a shot heard around the industry, and utilities since that time have thrown considerable resources into lobbying for stranded cost recovery. This effort has indisputably steered regulatory and legislative policies in a number of states. In the states pursuing utility restructuring to date, however, utility efforts are more accurately characterized as reactive than proactive. Perhaps the regulatory reforms now under way in California and New England were initiated by regulators as a simple response to political pressure from consumers for relief from high electricity prices, but regulators have been forced to delay the transition to accommodate the demands of utilities and their securities holders.

While eminently appealing on the surface, this explanation is less than satisfying. In particular, it implies that regulators are left in the politically suboptimal position of having initiated costly reforms that have generated virulent political conflict in the regulatory arena, without being able to bring benefits to anyone in the near term. This requires considerable myopia on the part of regulators as economic and political actors, or a particularly noble and selfless objective function. The financial position of incumbent utilities in California and New England relative to entrants' and wholesale markets' power prices was well known when the process began in 1994. That the effort of incumbents to secure recovery of their potentially stranded costs would not materialize in response to regulators' restructuring proposals requires a singular act of political nearsightedness by several different states' regulators. If instead such efforts were anticipated, then it is difficult to reconcile regulators' behavior in launching deregulatory reform proceedings with their incentives as political actors. The summary effect of regulatory reform in California to date, and probably well past 2002, is essentially zero for consumers and potential entrants, and a loss of several billion dollars for utility shareholders.

A better explanation for this no-constituent benefits puzzle, I believe, lies with a more politically sophisticated interpretation of regulatory behavior. Specifically, the standard prescription for the regulatory restructuring of this industry provides a means for regulators to reduce their downside political risk without substantially lessening their regulatory authority. In the states where deregulation is occurring, the principal sources of political conflict for regulators over the past two decades have been overbudget new generation facilities and regulators' obligation to allow utilities to recover their prudently incurred costs. For example, plants in California have arrived on line more than a decade late and at a staggering \$4.5 billion over budget (in 1985 dollars). In contrast, the standard prescription being promulgated by regulators entails no such obligation: regulators are unquestionably eliminating their obligation to provide a fair rate of return on investments in future power production facilities. In short, regulators are shifting from a system in which they are obligated to assure producers of an *ex post* nonnegative economic profit on capital investments, to one in which they need only assure investors of an *ex ante* nonnegative economic profit. Shifting this economic risk away from consumers and toward financial markets eliminates regulators' principal downside political risk, and one inherent in the cost-plus system of utility regulation.

Moreover, in no state entertaining electric utility regulatory reforms have regulators offered to withdraw their authority to intervene with the visible hand should market forces fail to perform in a suitably equitable fashion. While producers are nominally free of the administrative burden of regulatory price-setting proceedings, it would be inappropriate to characterize this newfound pricing flexibility as outside the purview of regulatory scrutiny. Instead, regulators perceive (correctly, I believe) that competitive entry will effectively discipline electricity prices outside of isolated transmission network "pockets." Therefore, the visible hand (in the form of generation market price caps) will need to be applied only sparingly.

Furthermore, regulators have not expressed any intent to abandon the rich panoply of so-called "public purpose" programs that benefit particular constituencies—energy efficiency programs, low-income subsidies, renewable resource procurement mandates, and so on. Because of the continued regulatory price control over the essential "bottleneck" facilities of transmission and distribution, regulators are able to maintain all of the social policies that constitute current regulatory mandates under the new regulatory system as well. Despite the "deregulation" nomer, the changes currently under way in electricity markets are more accurately characterized as a different system of regulation than as its absence.

In summary, although the emergence of a potentially competitive sector in this regulated network industry created a demand in high-cost states for lower prices, it also provided regulators in these states with the opportunity to reduce the downside political risk inherent in cost-plus regulation without substantially diluting their regulatory authority. To the extent that past investments in production assets by the regulated are water under the bridge, the new regulatory regime brings immediate benefits to regulators because they will no longer be obligated to provide an ensured stream of revenues to future investments by power producers. This option has considerable value in states that have experienced cost overruns and the ensuing political conflict from above-market power prices, but it has relatively little value in states that have not, the latter being those where the price gap (and potential consumer gains from competitive entry) are negligible.

Conclusion

In digging into the evidence that discriminates among these theories, I have attempted to rationalize the monumental changes in state-level electric utility regulation. My purpose in doing so is less to revisit the economic theory of regulation per se in light of recent developments, than to make a simple point about the prospects for price and entry deregulation in the electric power industry. Nearly half of the investor-owned electric utilities in the United States produce at average costs on a par with plausible estimates of the corresponding costs for potential entrants. Deregulatory efforts are being undertaken in states where entry could profitably occur at prices well below the average costs of incumbents, however. The political economics of regulation suggests that the institutional changes necessary to allow entry will occur, at most, in these latter states: there the immediate potential consumer benefits are large and obvious enough to generate sufficient political pressure to restructure an institution as entrenched as electric utility regulation.

While this theory comports well with the data for the handful of states where a formal deregulatory decision has been issued, given the self-selected nature of this sample one can hardly view the concordance as an unbiased "test" of the regulatory reform theory offered here. Most states that have opened formal investigations into deregulation have not yet concluded them, so now would not be a prudent time to attempt such a test in any case. Rather, the interesting and policy-relevant exercise is to ask what the data predict for states where formal decisions have not yet been made. The answer is that the states where deregulation is currently taking place are far more likely to end up as the exception than as the rule. Although it has become fashionable to view the electric utility industry as facing imminent upheaval in a sweeping wave of pending deregulatory change, for policymakers in most states the incentives for reform are lacking.

Having performed such an exercise, one is left with policy implications that are less than ideal. Normatively, regulatory reforms of the sort described at the outset of this paper would be desirable for this industry in its entirety. In the imperfect form in which regulation is practiced, the traditional utility regulatory process generates deadweight social losses well beyond those immediately associated with inefficient output prices. For the generation segment of power production, competitive entry can be expected to do a better job than continued regulation at making efficient risk and resource allocation decisions and in disciplining industry pricing behavior. These efficiency gains are a long-run phenomenon, however, and capturing them is not why deregulation is occurring. The need for short-run consumer benefits as a catalyst for the requisite institutional changes will limit widespread adoption of these regulatory reforms. Nevertheless, the arguments in this paper suggest that the incentives to pursue deregulation do line up correctly, inasmuch as the states where deregulation would be most beneficial are the states where deregulation is most likely to occur. To this extent, the significantly increased role that market forces are likely to play in this industry bodes well.

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Comments

Comment by Paul L. Joskow: Matthew White has written a very interesting paper exploring the economic and political forces that are leading to major structural and regulatory changes in the electric power sector in the United States. I agree with much in his paper. The most important factor driving change in the U.S. electricity sector is "the gap" he describes between the prices of generation services embedded in regulated retail electric rates and the prices for equivalent generation services that are available, or are expected to be available in the future, in unregulated wholesale markets. I also believe, however, that the political economy of regulatory reform in this sector is significantly more complex than the paper suggests. Additional factors influence the nature, diffusion, and sustainability of these structural and regulatory changes.

The introduction of competition in the electric power industry is not something that suddenly dropped out of the sky in California in 1994. Competitive wholesale generation markets have been growing for decades. The Public Utilities Regulatory Policy Act of 1978 (PURPA) marks a particularly noteworthy turning point because it required vertically integrated utilities to purchase power from independent power producers meeting certain thermal efficiency, fuel, and size criteria. Since passage of the act, about 60,000 megawatts of nonutility generating capacity have been built to supply electricity to utilities for resale under long-term contracts. In recent years nonutility generating capacity has accounted for more than 50 percent of net capacity additions.

The "reform model" that emerged during the 1980s envisioned an evolving industry in which utilities continued to have the obligation and exclusive right to serve retail customers in specified geographic areas at regulated retail rates.[1] Rather than building new generating plants to meet their needs, and recovering the costs through the cost-of-service regulatory process, utilities would acquire generating capacity under contract through competitive bidding programs in which non-utility suppliers would be free to compete; the competitive contract prices would be reflected in the rates charged by utilities to their retail customers. The Energy Policy Act of 1992 was an effort to facilitate the diffusion of this model. It gave the Federal Energy Regulatory Commission (FERC) authority to require utilities to make transmission, or ''wheeling,'' service available to support *wholesale* sales of electricity. It also reformed portions of the Public Utilities Holding Company Act of 1935 that impeded the entry of independent power projects that did not meet PURPA's criteria and created a new class of exempt wholesale generators (EWG) to compete to supply utilities' power needs. Moreover, the 1992 act not only contemplated continuing reliance on retail franchise exclusivity and associated utility service obligations, but also precluded FERC from requiring utilities to provide unbundled transmission service to *retail* customers.

Thus, the real surprise of the past two or three years is not that competition is coming to the U.S. electric power industry but that utilities are being required to unbundle the supply of generation service from the supply of transmission and distribution service and to allow retail customers to buy unbundled ''wires'' services so that they can shop for generation services directly in the wholesale market. It is not only that utilities are losing their *de facto* exclusive retail franchises. The loss of an exclusive distribution franchise per se just means that another party is free to build a competing distribution system. The reform proposals go well beyond this. Utilities are being required to separate the services provided by their transmission and distribution systems from the rest of their integrated organizations and to offer them as separate services at regulated rates. That is, they must make their ''wires'' available to all customers and suppliers seeking access to them as common carriers.

As the paper indicates, these changes are taking place in the United States most quickly in California and the Northeast where the gap between the price of generation service embedded in regulated retail

1. Joskow (1989).

rates and the expected prices for comparable generation services in competitive wholesale markets is the largest.[2] And these also are the regions where both the *potential* economic benefits for consumers and the potential economic losses to utilities from these reforms are the largest. While it is tempting to conclude that the price gap is the only cause of the changes that are now taking place, other factors that help to explain these changes should not be ignored in developing a complete understanding of institutional change in this sector.

First, the kinds of changes that are beginning to happen in the United States have taken place or are taking place in many other countries. This is a worldwide phenomenon, not a California or New England anomaly. The privatization and restructuring in England and Wales in 1990 is the most visible and most studied change, but related reforms have taken place in the electric power sectors in Chile, Argentina, Norway, Sweden, New Zealand, Canada, and Australia. The countries that make up the European Union have been wrangling for several years about electricity sector reforms that incorporate retail customer choice. Many developing countries are relying increasingly on private power producers to build and operate generating capacity under long-term contracts with incumbent state-owned utilities. These countries are implicitly adopting the wholesale competition model that was the basis of reform in the United States until recently. The economic circumstances and problems in these sectors vary widely from country to country, and

2. Some of the price comparisons in the paper are misleading, especially comparisons between wholesale generation service rates and bundled retail rates. New England has several "stand alone" distribution companies that buy all of their power supplies under contract, so it is possible to calculate directly their distribution service costs. In New England the distribution service prices for these companies vary from 2.7 cents per KWh to 4.0 cents per KWh. Transmission costs are in the 0.3 to 0.5 cent per KWh range. Therefore, the implicit "wires" price is in the range of 3.0 cents per KWh to 4.5 cents per KWh. Per kilowatt-hour distribution costs are likely to vary widely across the country because of differences in the mix of residential, commercial, and industrial customers that take power at different load factors, the average consumption level, the average load factor, the mix of above-ground and underground network, population density, and the age of the system. New England and California have electricity customer and consumption attributes that place them at the high end of the average "wires price" range. The wires prices above combined with the prevailing bundled prices of electricity in New England are consistent with an embedded generation cost in the 6.5 to 7.5 cents per KWh range, compared with a short-run average wholesale market price of 2.5 cents per KWh and a long-run wholesale market price of about 3.5 cents per KWh for generation service.

a price gap story of the type presented in the paper does not work in many of them. Yet despite the differences in economic conditions, similar reforms are taking place around the world almost simultaneously. The reforms in one country are influencing the pace and direction of reforms in other countries. Moreover, precisely the same companies that were created and participated in the independent power industry that emerged in the United States as a consequence of PURPA during the 1980s are now active around the world in building and operating generating plants. They are promoting some type of "private power model" to open markets for their services in countries around the world and with international financing agencies. At the very least, there is a demonstration effect: organizational arrangements that rely on competitive generation markets (previously thought to be unworkable) can work reasonably well, and benefits can accrue, at least to some interest groups, from various types of reforms that rely on competition to govern the supply of generation services.

Second, the basic model guiding electricity restructuring in California, the Northeast, and in many other countries is similar conceptually to the model that has guided restructuring, regulatory reform, and the diffusion of competition in the natural gas and telephone industries in this country and abroad.[3] Interest groups that have benefited from these reforms, especially large industrial customers, see electricity as one of the only remaining services that they must acquire from a monopoly, and they look to these other industries as reform models that can be applied to electricity. State public utility commissions typically regulate all three of these industries, and the FERC regulates both interstate natural gas pipelines and wholesale power and transmission service. Their thinking cannot be completely immune from what is happening in these other sectors. The reforms sweeping the other "natural monopoly" sectors necessarily lead interest groups, regulators, and other policymakers to ponder whether these concepts can and should be applied to electricity for private or social gain.

Interest Group Pressures

Any comprehensive effort to explain the political economy forces that are driving major institutional changes must define precisely the

3. Joskow (1996).

interest groups that are affected by these changes and how they can influence the regulatory and political process. This is an area where the paper could be expanded considerably. It focuses on only three interest groups: consumers, utilities, and regulators. To understand fully why the changes are taking place and where they are likely to lead, one needs a broader view of the interest groups that influence public policy affecting the electric power industry. Let me briefly identify the interests groups that matter and how they have behaved.[4]

LARGE INDUSTRIAL CONSUMERS. Electricity consumers are not a homogeneous group.[5] There are large differences in the importance of electricity costs in their budgets and in their ability to organize and influence the regulatory process. Industrial consumers have been the most active and the best organized in promoting the kinds of retail choice models that are emerging. And it is quite clear that they have had their eye on capturing a large share of the price gap that the paper identifies as lower industrial electricity prices. Why did these industrial customer groups become so influential in 1993 and 1994 and successfully lead a reform effort then but not in, say, 1988, when there already existed a significant and growing price gap? One of the things that California and the Northeast share, in addition to high electricity rates, is a shrinking manufacturing base and—especially in California, Massachusetts, Rhode Island, and New Hampshire—heavy dependence on military and aerospace firms within the manufacturing sectors. Economic dislocations in the early 1990s hit these states particularly hard. Companies from Raytheon in Massachusetts to Hughes in California used the threat of further job losses resulting from their relocation to other states to influence a wide range of state policies that affect the cost of doing business. It is not just that electricity prices are relatively high in these states; the costs of doing business overall are relatively high. Electricity prices were only part of a broader menu of cost reduction initiatives (taxes, disability insurance, tort reform, wages, and

4. I have left organized labor off of the list that follows. Many electric utilities are unionized and labor force reductions are likely to accompany restructuring, especially in the generation sector. Organized labor was slow to realize that these reforms may not be good for workers, and it has not yet been very aggressive in the regulatory and political arena. Where labor leaders are influential, it is unlikely that they will succeed in blocking reform. They are likely to be looking for transition arrangements for the workers affected.

5. Joskow, Rose, and Wolfram (1996).

work rules) that these industrial customers fought about with governors, legislators, and unions. The increase in the political influence of industrial consumer groups and the simultaneous decline of the power of environmental groups to influence economic policies were a very important stimulus to the electricity reform initiatives.

RESIDENTIAL AND SMALL COMMERCIAL CONSUMERS. Residential and small commercial consumers tend to be poorly organized, and electricity is a relatively small budget item. To protect the interests of small consumers, many states have designated public advocates (often the attorney general or an independent public advocacy office). These advocates, however, are organized to participate in rate cases, not to advocate sweeping industry changes. Many consumer advocates have been cautious about these changes in electricity; they have expressed concerns that smaller customers would not benefit from, or might be harmed by, the reforms as a consequence of bearing a larger fraction of the sunk costs of the system. There is a lingering perception among small consumer advocates that telephone and natural gas restructuring and deregulation harmed the little guys and helped the big guys, and this bias against anything that smacks of deregulation has carried over to electricity. Those representing small consumers tended initially to oppose rather than promote reforms. Ultimately, they have tried to tie price reductions for small customers to the price reductions achieved by large customers so that the little guys could benefit as well.

INDEPENDENT POWER PRODUCERS AND ENERGY MARKETERS. The Public Utilities Regulatory Policy Act of 1978 and the regulatory policies that implemented it created a new industry and a new interest group: the independent power producers (IPP). These are the firms that specialized in building power plants to provide electricity to utilities under contract. This industry, which did not exist in 1980, had grown enormously by the end of that decade. It is now a huge, rapidly growing international industry with many large firms building and operating power plants under contract around the world. In the United States the independent power producers were most influential in using the regulatory and legislative processes to create a market for their power plants at very creamy long-term contract prices in precisely the states identified in the paper as being on the frontier of the most recent reforms. And IPP contracts that are above market are a large component (as big or bigger than nuclear plants) of the price gap in all of the states where retail access and restructuring programs are proceeding most quickly.

The independent power producers have two primary objectives. First, they want to protect their existing long-term contracts since they typically carry prices that are higher than prevailing and expected market prices. Second, they want to expand the market for IPPs, either through the construction of new power plants to serve wholesale and retail customers or by creating opportunities to acquire power plants that utilities now own. Accordingly, they have supported stranded cost recovery by utilities (so the utilities have the money and incentive to honor their contracts), reforms that create opportunities to gain access to serve retail customers directly, *and* mandatory divestiture of utility generating plants to mitigate real or imagined vertical control problems and to create more opportunities for them to own generating facilities in the United States.

The developments in wholesale markets also created a related class of electricity suppliers. These are entities that either broker energy between buyers and sellers or buy for their own account from independent generators and then resell to wholesale customers. These markets and brokers may or may not own physical generating assets. They did not exist as a distinct nonutility business until recently. There has been very substantial entry in the past couple of years, and these suppliers have much to gain from expanding market opportunities from wholesale to retail markets.

ENVIRONMENTAL GROUPS. During the late 1980s and early 1990s, the influence of environmental groups in the regulatory arena expanded enormously, especially in California and the Northeast. Environmental groups skillfully used the institution of regulated monopoly (and its ability to bury the costs of policy initiatives in regulated electricity prices) to promote energy efficiency and renewable energy projects, and to incorporate real and imagined environmental externalities in planning and operating decisions. By 1990 the public utility commissions in California and the Northeast had been captured by a combination of environmental and IPP interests. It is (almost) amusing to read regulatory decisions issued by these commissions in the late 1980s and early 1990s in light of their most recent policy initiatives. For example, the Massachusetts commission justified its policies for dealing with environmental externalities with statements such as the following: "it is not the price of electricity that matters, but its global societal cost." A significant price gap already existed in 1990, but these commissions continued to pursue a social policy agenda that increased rather than decreased the gap. Something more happened between 1990 and 1994 than the sudden emergence of the price gap, which led these commissions to get religion about the virtues of customer choice and restructuring. The price gap was already there and growing.

The most powerful environmental groups have opposed reforms that promoted retail customer choice for the very rational reason that such changes would place great pressure on the taxation-by-regulation game that they have learned to play so well. The difference between what these commissions were saying in 1990 and what they are saying today is like the difference between night and day. Other forces pushed the need to deal with high electricity prices to the front of the regulators' agenda. The growing relative political power of industrial consumers and IPP interests during the early 1990s helps explain why the reforms were embraced by commissions that had previously showed more interest in social policy objectives than in keeping the price of electricity low.

UTILITIES. Most but not all utilities initially opposed the kinds of reforms that are taking place in California and the Northeast. They recognized that they had a lot to lose if they could not recover the costs of sunk commitments in generating facilities and PURPA contracts that account for the bulk of the price gap. In many cases they had more than their entire equity to lose. Moreover, unlike many large industrial customers who were pressing governors and legislators for lower electricity prices, they could not threaten to move their businesses to Mexico, Malaysia, or even Georgia. Utilities, however, are not without some ability to influence local political decisions. To affect the rate and directions of the reforms and the handling of stranded or transition costs in the restructuring and regulatory reform program, utilities have formed coalitions with environmental groups, groups representing residential and small commercial customers, and IPP groups.

More importantly, there are legal impediments that public policymakers must confront if they try to erase the price gap without providing reasonable sunk cost recovery for the incumbent utilities. As the paper indicates, it would have been very difficult to have erased the price gap through ordinary regulatory procedures. The generating investments at issue had typically been approved by regulators and allowed in rates through standard cost-of-service regulatory principles. In the case of nuclear plants, many commissions had already exacted concessions from utilities before accepting the costs as reasonable. With regard to PURPA contracts, utilities were under legal obligations to enter into them, and their terms and conditions were frequently mandated by state commissions. If a regulatory agency had tried to exclude these costs from prices after the fact in a rate case, it would have faced serious legal problems under state law and constitutional protections against takings of property without just compensation as articulated by *Hope* and related cases.[6]

The paper suggests that reforms built around a retail access model could eliminate this problem by allowing customers simply to bypass paying for the sunk cost obligations by taking only regulated transmission and distribution service and buying generation service in the wholesale market. There are potential legal impediments here too, however. Few state regulatory statutes give commissions authority to compel utilities to give access to their property (the transmission and distribution systems) to third parties or to divest their generating facilities. Moreover, statutory changes that would provide such authority still would have to confront the constitutional question of just compensation for the utilities in return for providing access to their property. The average accounting cost of a piece of an integrated firm (the ''wires'') may not be considered by the courts as just compensation when the generation, transmission, and distribution investments were made in an integrated fashion to meet legal obligations to provide a bundled service to all retail customers in the franchise area. Any effort to compel open access and divestiture without reasonable compensation for sunk cost commitments would have led almost inevitably to years of litigation and delay, a situation that may be emerging in telecommunications. Time is a potential friend of the utilities, especially if the alternative is complete bypass by customers of payments for sunk cost obligations. This is the case for two primary reasons. First, the sunk cost obligations slowly go away over time as generating plants are depreciated and PURPA contracts expire. Second, the price gap is much larger in the

6. *Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944).

short run than the long run because of excess capacity and market prices today that are below the long-run entry cost. As demand grows, wholesale market prices are expected gradually to rise. On the other hand, relying on delay is a very risky strategy since the period of time required to recover above-market costs could be decades or more.

Implications of Interest Group Pressures

By taking all of the interest groups into account, along with the paper's evidence and appropriate emphasis on the price gap, we can get a much more complete picture of what is going on. The pressure is indeed greatest in those areas of the country where the price gap is largest because there is the most to gain by industrial customers from reforms and the largest potential market opportunities for IPPs and energy marketers. At the same time there are important interest groups that have opposed these reforms. Because of the conflicting interests of these groups, the stage appears to be set for some kind of compromise in which all of the competing interests get something. A natural compromise looks something like the following. All customer groups, not just the large industrial customers, get some rate relief from the restructuring process, but not nearly as much as would be implied if the price gap were fully erased instantly. Utilities get most of their sunk cost commitments back through a customer access charge that is competitively neutral. In return, utilities must open up their retail franchises to competition, agree to turn over control of their transmission networks to independent operators, and "voluntarily" divest some or all of their non-nuclear generating assets to deal with vertical and horizontal market power concerns and to define a value for stranded costs.[7] Independent power producers get their existing contracts secured, get access to retail customers, and an opportunity to buy utility power plants when they are auctioned. Environmental groups get assurances that funds will be set aside by the distribution company to pay for energy efficiency programs and to help to fund environmentally benign generating technologies. These funds, however, will be collected as specific customer charges attached to the distribution portion of a customer's bill rather

7. Potentially stranded generation costs are the difference between the book value of the generating plants used for rate-base purposes under conventional cost-of-service regulatory procedures and the market value of the generating plants.

than buried in the bundled price of electricity. This is precisely the kind of compromise that has emerged in California and is reflected in the legislation signed by Gov. Pete Wilson in September 1996. A similar compromise framework is emerging in Rhode Island, Massachusetts, New York, and Pennsylvania.

Implications for Restructuring and Regulatory Reform

The paper suggests that the regulators in the states that are at the forefront of these reforms are having their cake and eating it too. That is, they can defuse the political pressures that they are under by instituting California-like reform and still retain their authority to step back in and regulate the system if things do not turn out as they expect or when the heat is off down the road. I do not think this is likely to be the case or that any thoughtful regulators think that it is. Once a state removes a utility's traditional obligations to serve, requires unbundled rates, provides open access to the network, gives retail customers a choice, deregulates generation prices and entry, and requires utilities to divest a significant amount of generating capacity, it will be very difficult for a state commission to turn the clock back and regulate the way it has in the past. A great deal of a state's regulatory authority comes from the vertical integration of generation, transmission, and distribution within a single operating company and the associated internal (rather than wholesale market) transfer of generation to serve retail customers. Once generation is provided by separate corporate entities, even if they are affiliates of the same holding company, the regulation of any sales of generation at wholesale is preempted by FERC under the Federal Power Act. Moreover, as ownership in unregulated generators is dispersed among competing suppliers, they will aggressively resist either state or federal commission efforts to reregulate them and are likely to press for statutory changes to protect them from future regulatory holdups. Of course, if things work out badly, new regulatory arrangements can emerge, but it would be foolish for a state commission to think that adopting a California-type model will make it easy for the state regulators to step back into their traditional regulatory role a few years down the road. It will not be easy at all. Moreover, if it is perceived to be easy to reregulate, investors will be reluctant to commit funds to finance new projects. If the California and Massachusetts models reach fruition as contemplated, the state regulators will be left regulating distribution tariffs under incentive regulation mechanisms and not much else. They may even be able to return to the quiet life of the 1950s and 1960s, and that would be a good thing.

Let me turn now to the question of how far these reforms will spread. The paper indicates quite correctly that the price gap that is stimulating these changes varies widely from state to state. It implies that the retail choice reform program and everything that goes with it will be limited to the states where the gap is large and will not spread to include the states where the gap is small or even negative. Unless the reforms in California, New England, and New York lead to a complete mess from a cost or reliability perspective (not an impossibility), I expect to see these reforms gradually march across the country in one form or another. The speed with which the reforms will be introduced in individual states and the implementation details will vary, but I believe that we are on a path that will bring these restructuring reforms to the entire country during the next decade.

I also believe that the paper significantly underestimates the size of the price gap and the number of states where the gap is positive and significant. As a result, the number of states in which there are large customer incentives for reform is much greater than the paper suggests. The data in table 1 for the cost of a new entrant are outdated (the most recent is 1990), and the associated entry costs are too high compared with the actual entry costs today. The thermal efficiency of combined-cycle gas turbine (CCGT) technology has continued to improve, equipment costs have continued to decline, and the overall cost of base-load CCGT technology is now in the 3.0 to 4.0 cents per KWh range, depending on location, fuel price assumptions, and financing assumptions. The best number for the entry price in tables 4 and 5 is probably 3.5 cents per KWh. Moreover, the average annual price of electricity in wholesale markets today is much lower than the entry cost—in the range of 2.0 to 2.5 cents per KWh—in most regions of the country. Precisely how fast demand and supply conditions will change to bring prices into long-run equilibrium is very uncertain and will depend, among other factors, on how and how quickly retail competition opportunities expand. I doubt there will be much horizontal market power in generation markets to hold prices up. These short-run opportunities to obtain lower prices in the wholesale market further increase the number of states where there are large potential cost savings for customers that can buy directly in the wholesale market.

Moreover, the price gap is not the only force at work here. IPP and energy marketing interests will press for a retail choice model whether there is a significant price gap or not. Many industrial customers with facilities in multiple states are interested in dealing with a single national energy services supplier that can arrange for their electricity (and gas) needs at all of their facilities around the country. Energy marketers are gearing up to provide this kind of national accounts service. The opportunities to do so will be facilitated by reasonably common institutional arrangements across states. There are also a growing number of ''low-cost'' utilities that see potential benefits in opening up all systems to competition to increase the size of the market and the prices at which they can sell energy produced from their excess generating capacity. That is, they see little to fear in their own areas from competition because (they think) their current prices are competitive, and they see opportunities in other retail service areas where prices are higher, especially if there are opportunities to provide service in a way that allows customers to bypass sunk-cost payment obligations. I suspect, however, that their interest in these reforms and their support may change considerably if generation divestiture becomes a key piece of the reform package.

Electricity is traded in regional markets, not in markets defined by the boundaries of individual states. It will be increasingly difficult to manage the operation of regional wholesale markets efficiently when the constituent states have very different regulatory institutions and industry structures; furthermore, the power suppliers in the reformed states will have very strong interests in promoting similar reforms in neighboring states. For example, the paper indicates that Connecticut has decided against moving quickly to a retail choice model. However, it will be hard to keep the innovations from spreading to Connecticut if Massachusetts, Rhode Island, and New Hampshire do it, and it works as they expect it will.

Finally, both Congress and the Clinton administration are likely to propose legislation in the 105th Congress that will either require or encourage states to change regulatory institutions in ways that allow for retail customer choice and promote competition in generation markets. That is, there will be pressure for the federal government to partially or fully preempt state authority regarding retail access. Large industrial customers, IPPs, and energy marketers in both the electricity and gas industries are likely to see the new Republican Congress as a particularly attractive forum within which to debate industry restructuring. And Congress is likely to view electricity restructuring as a particularly juicy issue, perhaps the juiciest since telecommunications reform. If legislation is ultimately passed, it is likely to require or strongly encourage retail customer choice and reasonable uniformity in basic institutional arrangements across the country. As with reforms in telecommunications and natural gas, this debate will pit "states' rights" proponents against "federal preemption" proponents. Precisely how things will sort out will be interesting to watch, but I think that the states' rights proponents may fare just about as well as they have on telecommunications and natural gas policy reforms.

Overall, it is unlikely that the long-run institutional equilibrium for the electric power industry will involve one set of states with unbundled rates, vertical separation of generation, and customer choice, while another set of states continue under the status quo. What the long-run equilibrium looks like will depend heavily on the performance of the first restructuring and regulatory reform initiatives now being implemented in California and the Northeast, and the complex interactions of the key interest groups that I have discussed.

Comment by Jerry Hausman: Matthew White has written an interesting paper on economic and regulatory outcomes when the technology changes in a highly regulated industry. New generations of power generating plants operated with prevailing low prices of natural gas have lower average total costs in many cases than the average variable costs of many generating plants that were constructed during the 1970s and 1980s. In a competitive industry when technology changes and costs decrease, prices typically decrease also. Economic efficiency increases and consumers benefit from lower prices. The question that the paper considers is whether regulators will permit similar behavior in regulated electricity markets. Supporters of regulation typically state that regulation causes regulated markets to behave like a competitive industry, which I have usually taken to be an ill-conceived approach since the technology that leads to regulation would not lead to a competitive outcome. Differing from a competitive situation, utilities here claim that they should recover the potentially "stranded costs" that they prudently incurred under regulation. Part of the stranded costs arises from unrealistic depreciation policies used by regulators and part arises from the change in technology. What can economics say about the efficient outcome?

Professor White concentrates on the price gap between the regulated price in a given state compared with the prices that arise from allowing competitive new entry in power generation. The price gap arises from very high average prices in some states, as depicted in figure 2, which demonstrates that states with the most activist regulatory agencies also have among the highest prices in the United States (for example, Massachusetts, California, and New York). Professor White does not analyze the sources of these higher prices, but he does note that the high prices arose in part from regulators forcing utilities to purchase power from high-cost independent suppliers under the Public Utilities Regulatory Policy Act of 1978. What proportion of the higher prices arises from this regulatory requirement and other ill-designed regulation and what proportion of the higher prices arises from higher costs particular to these regions is not determined. I find it implausible, however, that the higher prices can be explained by higher costs totally. Thus, regulation has led to an adverse effect on consumers and state economies because of the higher electricity prices that activist regulators caused, at least in part. Nor have the regulated companies in these states "captured" the regulators at the expense of consumers. Analysis of the regulated companies' returns (not considered in the paper) demonstrates that companies in the high-prices states have not earned above risk-adjusted returns. Indeed, the reverse is probably more in line with the data. Thus, activist regulation has benefited no identified group of consumers or the regulated companies. Regulation that has led to high prices has created deadweight loss and productive inefficiency in the economy.

In these same states the price gap is now the largest because of the higher average prices compared with prices that would occur under competitive new entry. Deregulation of power generation in these states would lead to large gains to consumers and to economic efficiency. The problem of stranded costs, however, would remain. Professor White concludes that plausible regulatory reform permitting competitive entry would lead to the largest gains in California, New York, New Jersey, Massachusetts, and the other New England states. These states are essentially the high-price states from figure 2. Professor White notes that regulators in California, Massachusetts, and elsewhere, rather than allowing for deregulation and lower prices, have levied "transition charges" to pay for the stranded costs. Of course, these transition charges are a tax with the associated deadweight losses and other efficiency losses to the economy. While a "regulatory compact" may exist under which the regulated companies can claim they should recover their stranded costs, the efficiency losses to the economy would likely be much less if a tax raised from overall consumption (for example, a broad-based sales tax) were used instead, especially if the price elasticity of demand of electricity is significant.

The regulators' proposed solution, of transition charges, causes no one to benefit from the change in technology, which is a very strange outcome and far removed from the "competitive standard" used by those economists who favor regulation. Consumers do not benefit, potential entrants do not benefit, and shareholders of the regulated companies have not benefited. Professor White discusses these results within some positive theories of regulators' behavior. He presents no model or empirical tests, however, so the discussion, while interesting, does not lead to sharp conclusions.

I believe that Professor White may miss the more important lessons that arise from the change in technology. The high regulatory states have high prices and do not appear to allow consumers to benefit from the change in technology. The policy prescription should thus be to remove the problem: power generation should be deregulated by Congress since it now is a competitive technology, and regulation should be limited to transmission where competition does not exist. The stranded cost problem is a political decision that should be solved by state legislatures. Legislatures can decide how much of the stranded costs the utilities will receive. Regulation largely caused the current problem, and no reason exists to believe that regulation will solve the problem. Since no economic reason exists for regulation of a competitive technology, regulation should be eliminated. Economic efficiency would increase, consumers would benefit, new entrants would benefit, and at least some of the current regulatory staffs could be employed in more productive sectors of the U.S. economy.

Commentators' References

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