Was California's Market Structure Responsible for Its Electricity Fiasco?

The successes and failures of electricity restructuring have been well chronicled, but do we know why some restructured markets have been more successful than others? Although many factors affect how competitive a market is, some factors may have more of an influence than others. Today regulatory agencies are focusing on market design and regulating firms' behavior as the best means to achieve a competitive market. But is a better market design what really leads to a more competitive market? What impact does the structure of the industry have on competition?

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In their CSEM Working Paper, "Market Structure and Competition: A Cross-Market Analysis of U.S. Electricity Deregulation" (CSEM WP-126), James Bushnell (UC Energy Institute), Erin Mansur (Yale University) and Celeste Saravia (UC Berkeley and UC Energy Institute) delve into the relative impacts of market structure and market design on the level of competition in the California, New England and PJM (i.e., Pennsylvania, New Jersey, Maryland) electricity markets. In terms of producing competitive wholesale prices, the California market has been fairly widely described as a failure; whereas, the New England and PJM markets have been declared relatively successful. The authors explore the characteristics of the three markets to understand why the eastern markets were more competitive and what role market structure played.

Bushnell, Mansur and Saravia (BMS) compare the structure and design of the California, New England and PJM markets, and measure their performance relative to benchmarks representing both perfectly competitive and strategic behaviors. While the three markets operate under diverse market designs, BMS abstract away from these differences to focus on the impact of structural differences in each of the markets to explain their market prices. In particular, BMS estimate prices in the three markets under scenarios with and without vertical arrangements, i.e., long-term contracts between the retail and wholesale suppliers. Vertical arrangements include long-term contracts between a generation firm and a retailer, as well as the formal integration of a generation firm and utility retailer within the same company. These arrangements help reduce the incentive of generation firms to raise spot prices because those firms earn the spot price for only the portion of their production that is not obligated under the vertical arrangement. Since their spot sales are relatively small, they have less incentive to reduce output further and raise spot prices.

Using actual market data, the authors estimate an upper and lower bound for market prices in each market. The upper bound is set by estimating a Cournot equilibrium price, where firms are assumed to strategically determine the quantity they will produce

Will Real-Time Pricing Really Deliver Savings?

If some customers had to pay the actual hourly cost of electricity, instead of an averaged flat rate, would they be better off? Would California? Many economists argue that averaging the actual cost of electricity over time encourages customers to use more electricity at peak times than they would if they had to pay the real cost. The cost of purchasing wholesale electricity for peak periods on hot summer days can be exorbitant, but customers don't see that cost. What would be the impact on the cost and price of electricity, and on customers as a whole, if some paid the real-time price of electricity, higher at peak times, but also lower at off-peak times?

Severin Borenstein, Director of the UC Energy Institute and Professor at the UC Berkeley Haas School of Business, examines these questions in CSEM Working Paper, "The Long-Run Effects of Real-Time Electricity Pricing" (CSEM WP-133). Borenstein simulates the long-run impact of customers paying the real-time price (RTP) of electricity instead of a flat rate and reports the impact on total electricity consumed, prices charged to customers, and amounts of each type of generation needed, as well as the total value created by RTP. Theory tells us that since RTP shows customers the actual price of electricity, it can therefore best inform customers as to the true cost of turning on their electricity at any given hour. If customers had to pay the actual cost of electricity at 5:00pm on a hot summer day, they might decide to reduce their air conditioning use and thereby lower not only their electricity bills, but also the overall cost of procuring electricity. Correspondingly, electricity during off-peak times is cheaper and RTP may motivate customers to shift some of their electricity usage to less expensive periods.

Borenstein's base case simulation, which assumes that customers are equally price sensitive at all times, shows that even under conservative assumptions there is a significant societal gain by having customers on RTP. In fact, Borenstein shows that by having just one-third of total electricity demand on RTP, the overall gain in efficiency would be more than $100 million annually. Although these simulations do not take into account the implementation costs of moving to RTP, these savings dwarf the expected implementation costs. In 2001, California paid a one-time cost of $35 million to install meters (arguably the largest implementation cost component) for the largest customers in the state, who comprise about one-third of total demand.

Borenstein then analyzes a scenario where customers are more price responsive during peak periods than during off-peak periods, as many analysts believe. The results show even larger annual benefits – nearly $160 million. Greater price responsiveness at times of high demand leads to larger reductions in peak demand, and consequently, larger reductions in the need for peak generation capacity. Under this scenario, fewer peaker plants are needed relative to the base case, which is what drives the additional gains in efficiency.

Confirming earlier theoretical work Borenstein has done with Stephen Holland (CSEM Working Papers #106 and #116), these simulations show that not only are the RTP customers as a whole better off when they move to RTP, but the customers remaining on flat-rate plans are also better off. As additional customers move onto RTP, however, Borenstein shows that they reduce the benefits to those customers already on RTP. With the addition of more customers on RTP, the price of electricity will fluctuate less between peak and off-peak periods, reducing the potential savings RTP customers could earn by adjusting their consumption. Given the decreasing incremental benefits of adding more customers onto RTP, drawing the line at including the largest customers may yield the largest net efficiency gain.

Although implementing RTP is likely to generate large efficiency gains, Borenstein argues that it would also cause significant wealth transfers because some customers have peakier demand than others. With a flat-rate price, customers with flatter demand profiles subsidize those customers with more peaky demand profiles. By paying an averaged flat-rate price, the peaky demand customers don't pay rates that fully reflect the higher cost of serving them. Borenstein analyzes the actual demand profiles of a sample of 317 large California customers and finds that their demand profiles vary widely. Some have very peaky demand profiles, while others have relatively flat-demand profiles. Customers on RTP with flatter demand profiles would pay the actual cost of their usage, which would not include the higher cost of meeting the needs of the peaky-demand customers. Borenstein finds that these wealth transfers from RTP may be quite large, creating a potential political obstacle to RTP.

Borenstein's simulation results support the view that there would be large societal benefits if even some electricity customers were put on RTP. His results from several scenarios indicate that putting the largest customers, who make up about a third of all demand, would result in significant efficiency gains. The potential fly in the ointment, however, is the likely resistance from peaky-demand customers who would then be forced to pay prices that more closely reflect the true costs of serving them. Even though many would agree that prices should reflect costs, ending a subsidy is likely to be an uphill battle.

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California's High Gasoline Prices: Scarcity or Gouging?

In March 2004, California gasoline prices once again increased rapidly to more than 30 cents above those seen in the rest of the country. But the state's cleaner-burning (CaRFG) gasoline costs only about 10 cents more to make than conventional gasoline. A number of observers have attributed the periodic price spikes, and the widening average differential between California and U.S. average prices, to increasing scarcity of refinery capacity among plants that are equipped to manufacture CaRFG gasoline. Many of those same observers have discounted or dismissed the possibility that refiners in the market could drive prices above competitive levels.

In CSEM Working Paper #132, "Market Power in California's Gasoline Market," Severin Borenstein, James Bushnell and Matthew Lewis (BBL) argue that dismissals of the idea that firms in California's CaRFG gasoline market would be able to drive prices above competitive levels are not well founded. The authors don't discount or dispute previous analyses that have found that the elevated prices are consistent with competitive markets. Rather, they build on those analyses, demonstrating that the data are also consistent with some firms exercising market power: withholding small amounts of gas from the market in order to drive prices up. They then discuss methods for, and difficulties in, distinguishing between competitive pricing and market power.

BBL begin by presenting the basic model of pricing and market power in the absence of storage or an import supply that can respond as prices rise. They demonstrate how prices can be volatile even in the absence of market power, and can at times significantly exceed the average cost of production. They then go on to show why this is not the whole story. The same circumstances that are likely to cause price volatility in a competitive market — demand that is not very sensitive to price and supply that is capacity constrained — are also likely to create incentives for sellers to exercise market power.

It is often said that gasoline prices follow the simple economics of supply and demand; BBL argue that equally simple are the economics of market power, a firm recognizing that decreasing supply will tend to drive the price up for all product that it sells. In fact, the authors argue that in the complex calculation that goes into a California refiner's product mix decision, it would be quite surprising to learn that they do not consider the effect of their production decisions on market prices.

The authors then expand the analysis to take into account the effect of gasoline storage. Not surprisingly, storage limits the price swings that occur in a market, whether those swings are due to market power or true scarcity of the product. BBL discuss the long-run equilibrium investment in storage that one would expect if there were free entry into the gasoline storage business. They then analyze the potential barriers to entry in this line of business and the possibility for a company that is in the gasoline storage business to exercise market power in that function. Their analysis suggests that there are regulatory, political and economic barriers to entry and that some firms could have an incentive to thwart entry of new storage.

BBL also examine interactions between storage, pipeline control, and refining in the incentive to exercise market power. The transport of refined product is a market in itself. While there is little evidence of market power in international or interstate shipping of gasoline, local pipeline distribution is more vulnerable to market power, which is why it is regulated by the Federal Energy Regulatory Commission (FERC). The authors argue that regulation may effectively control direct exercise of market power through high prices for pipeline transportation, but pipeline owners may still have adverse incentives if they are active in the refining or storage businesses as well.

California used to export large quantities of gasoline, but in recent years has become a net importer. BBL note that alternative sources can augment west coast refinery production, but point out that this will come at a cost to consumers. Due to their distant location, supplies from the gulf coast, Caribbean or beyond have higher transportation costs, raising incremental cost by 5 to 20 cents per gallon. In addition, distant imports have longer travel time, so they cannot respond as quickly as in-state production to unforeseen shifts in the supply/demand balance. The authors show that the cost and time constraints on gasoline imports intensify the incentives in-state firms have for exercising market power.

The authors state clearly that they present no evidence that refiners have exercised market power in California's gasoline market. In fact, they discuss why it would be very difficult to demonstrate to any reasonable level of certainty that a firm is doing so, pointing out that these are the same reasons that attempts to regulate gasoline prices have in the past harmed consumers and would be likely to fail again if attempted now. Rather, BBL show that firms in the California gasoline market may face significant incentives to exercise market power, and that it would be natural in an unregulated market for a firm to respond to those incentives.

Because it is very difficult to distinguish between market power and true scarcity in gasoline markets, and because they argue that antitrust laws are unlikely to effectively protect consumers from market power in gasoline, BBL suggest that prevention is a much more attractive public policy than prosecution. They conclude by discussing policy options for reducing market power incentives within California's gasoline markets. They argue that two options are promising: a) allowing non-CaRFG gasoline into California but charging the importer a variance fee, and b) requiring the State to purchase some of its fuel requirements through long-term contracts. Both of these options could diminish a firm's incentive to exercise market power in the California gasoline market.

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Did Electricity Restructuring Lead to Generation Efficiencies?

Restructuring has fundamentally changed the way plant owners are paid for their electricity. While investor-owned utilities' rates were based on the costs of their plants, owners in restructured settings are paid a price determined by the market. Plant owners now have a stronger incentive to minimize their costs so they can earn the difference between the market price and their costs. Have these cost savings been realized, and, if so, how big are they?

In their novel study, Kira Markiewicz, Nancy Rose, and Catherine Wolfram (MRW) take a first crack at this question. They seek to measure the impacts of restructuring on investor-owned utility (IOU) plant operating costs. CSEM Working Paper # 135, "Has Restructuring Improved Operating Efficiency at US Electricity Generating Plants?" compares plant operations in states that have restructured with those in states that have not. They compare the change in input expenditures for each group of plants to identify the gains or losses in efficiencies due to restructuring. As an additional benchmark, MRW look at the operating characteristics of cooperatively- or publicly-owned municipal or federal plants, i.e., MUNIs, between 1993 and 1999 and compare their plant operating efficiencies against IOU plants in states that have restructured. MUNIs have been for the most part immune from restructuring so they offer another comparison from which to estimate the impacts of restructuring.

FIGURE 1: AVERAGE EMPLOYEES PER MW IN RESTRUCTURING AND NON-RESTRUCTURING STATES

Using annual generating plant-level data, MRW estimate the changes in a variety of input expenses, such as non-fuel operating expenses, number of employees, and fuel use, in the three groups of plants. Their results indicate that IOU plant operators in restructured states reduced labor expenses by almost 6 percent [See Figure 1] and non-fuel expenses by almost 13 percent [See Figure 2] relative to IOU plants in non-restructured states. Even accounting for changes in output in the plants in restructured states and the consequent reductions in input expenses, MRW still see labor expenses decline by 4 percent and non-fuel expenses by 10 percent. IOU plant expenses in restructured states fell by even more relative to MUNI plants: employment dropped

by 13 – 15 percent and non-fuel expenses by 21 – 23 percent. The authors find that even IOU plants in non-restructured states significantly reduced employment and nonfuel operating costs, perhaps in response to the threat of competition. In none of the estimations do IOU plant fuel expenses indicate any significant change due to restructuring.
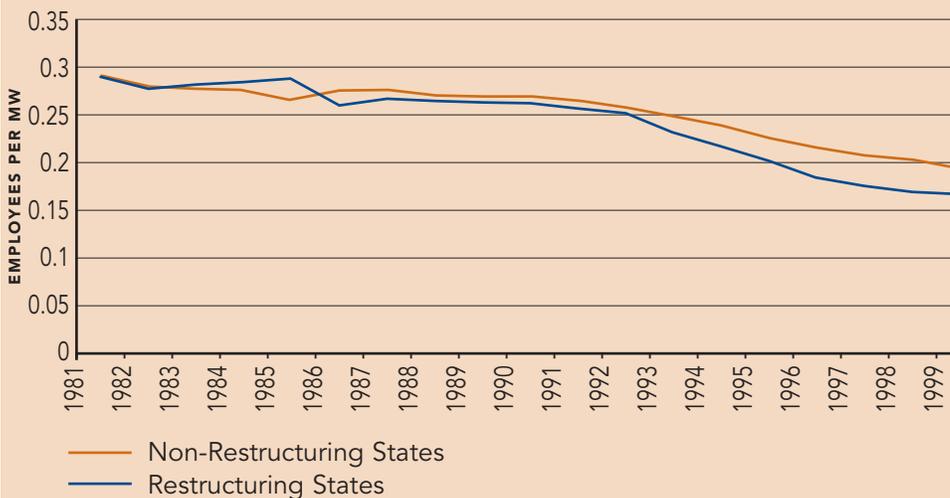
The authors test the robustness of their findings by testing alternative explanations for the efficiency gains in restructured states.

One possibility is that the decreased expenses were due to the retirement of inefficient plants or to inefficient plants dropping out of the data set because they were transferred from an IOU to a merchant owner. To test this theory, MRW estimated the input changes only including those plants that had been in the data sample for the entire period. The results did not vary – indicating that this selection bias was not an important factor.

Another hypothesis is that the gains in efficiency among plants in restructured states were attributable to plants that were less efficient on average prior to restructuring. To explore this possibility, the authors divided the plants in the restructured states into two groups: cheap (i.e., efficient) and expensive (i.e., inefficient) plants. MRW's results suggest that most of the overall declines in input expenses are due to reductions in inputs associated with the "expensive" plants, suggesting that restructuring brings the expensive units more in line with the already efficient plants. Since restructuring

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to achieve the most-profitable price. The lower bound is estimated assuming perfect competition (i.e., each firm is a price taker). The authors argue that a market's structural factors (such as the existence of vertical arrangements or long-term contracts) determine these upper and lower bounds on prices, while the specific market rules (such as the auction format) influence where actual prices fall within these bounds.

To identify the impact of vertical arrangements, BMS estimate a Cournot equilibrium with and without long-term contracts. Table 1 shows the results of these estimates for all hours and for just peak hours, along with the actual prices in each market for the sample period of summer 1999, before the California crisis. This comparison reveals that actual prices for each of the three markets in the peak periods approximate the Cournot estimates - indicating that the firms in all three markets were able to achieve prices close to the theoretical upper bound. The authors conclude that market rules appear not to have had a significant impact on these outcomes because the Cournot estimate with vertical arrangements so closely predict the actual prices. A result of particular interest is that the Cournot estimates without vertical arrangements yielded extraordinarily high prices in the eastern markets, which were not indicative of actual prices. Excluding vertical arrangements, these eastern markets actually had a far less competitive market structure than did California. When accounting for vertical arrangements, the range of possible market prices was significantly narrowed, greatly reducing the scope for the potential impact of market rules.

The implication of these results is that the presence of long-term contracts or other vertical arrangements significantly enhanced the competitiveness of the market prices. California's vertical arrangements were less extensive than either the New England or PJM markets. Although the results in Table 1 show California's prices to be lower overall than the other markets during 1999, this is due to many other factors. Ignoring vertical

TABLE 1: PRICES BY MARKET AND PEAK PERIOD DURING THE SUMMER OF 1999

PANEL A: ALL HOURS

VARIABLE	MEAN	STD. DEV.	MIN	MAX
California Actual	29.69	19.10	1.00	224.99
Competitive	28.65	12.90	1.18	233.00
Cournot	34.03	15.36	1.19	233.34
New England Actual	36.96	56.66	1.00	1003.21
Competitive	34.66	19.67	10.27	357.43
Cournot	38.69	48.17	7.09	712.80
Cournot n.v.a.	150.85	223.33	0.00	999.99
PJM Actual	45.92	122.76	0.00	999.00
Competitive	31.13	8.10	18.63	72.79
Cournot	60.46	131.73	21.30	1000.00
Cournot n.v.a.	797.45	394.07	18.51	999.99

PANEL B: PEAK HOURS (11AM to 8PM Weekdays)

VARIABLE	MEAN	STD. DEV.	MIN	MAX
California Actual	43.15	26.99	17.16	224.99
Competitive	35.06	19.92	24.70	233.00
Cournot	44.50	20.73	24.97	233.34
New England Actual	55.05	82.86	17.67	753.17
Competitive	41.11	32.19	29.75	357.43
Cournot	59.05	76.97	25.55	712.80
Cournot n.v.a.	303.32	312.36	30.26	999.99
PJM Actual	97.31	210.17	11.22	999.00
Competitive	37.41	9.16	22.77	72.79
Cournot	115.14	225.90	24.61	1000.00
Cournot n.v.a.	998.89	32.65	31.29	999.99

* Note: There are 2,928 hourly observations: 880 peak and 2,048 off-peak. Cournot n.v.a. means no vertical arrangements.

arrangements, California's market structure during 1999 was the most competitive of the three. The lesson from the New England and PJM markets is that without vertical arrangements, their spot market prices would have been much higher. The expectation based on these findings is that California's market prices during the crisis period of 2000 would have been much lower if there had been vertical arrangements comparable to those in the eastern markets.

Electricity restructuring and anti-trust policies have focused on refining market design rules and monitoring horizontal market structure. This study suggests that the presence or lack of vertical arrangements has more to do with the competitiveness of electricity market prices than either market rules or the horizontal structure. In trying to analyze the mistakes of past restructuring efforts, BMS provide compelling insights into an influential component of a competitive market – the existence of vertical arrangements. This study complements the earlier work done by Professor Mansur in CSEM WP-117 which concludes that those firms with vertical arrangements have much less of an incentive to manipulate the market price so that it exceeds the competitive level. Creating incentives for utilities to seek out vertical arrangements is likely to be more productive in promoting competition than would regulating producers' behavior.

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DID ELECTRICITY RESTRUCTURING LEAD TO GENERATION EFFICIENCIES?

FIGURE 2: AVERAGE NON-FUEL EXPENSES PER MW IN RESTRUCTURING AND NON-RESTRUCTURING STATES
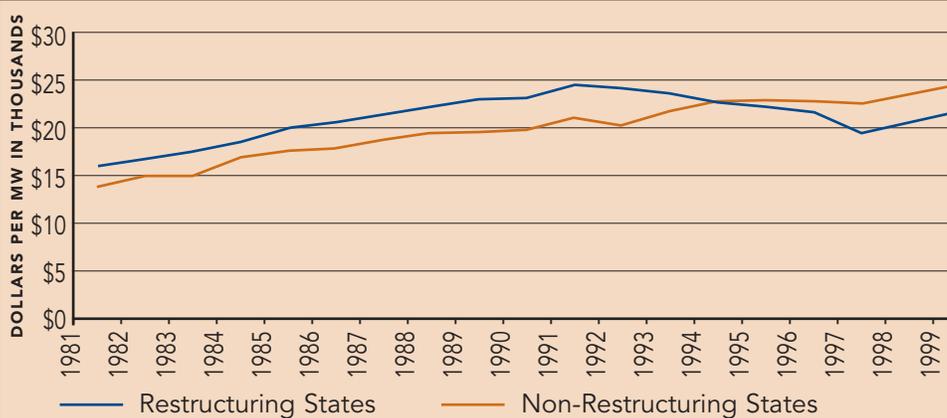
seems to have had the effect of improving the efficiency of the least efficient plants, it is likely that introducing restructuring in non-restructured states could lead to improvements for at least the inefficient plants in those states.

An interesting observation through these comparisons is that the MUNI plants showed the least amount of efficiency gains through the 1992-99 period. Even the efficient plants in the restructured states showed greater gains than did the MUNI plants. One might argue that since the MUNI plants tended to be smaller and newer, there were few efficiency gains to be had. However, it was the smaller and newer IOU plants where the greatest efficiency gains had been realized.

This research provides some of the first estimates of the impact of electricity generation sector restructuring in the United States on plant-level efficiency. The results suggest restructuring may yield substantive medium-run efficiency gains. It is possible, however, that the longer run effects will be more striking as firms respond to the new incentives created by restructuring with investments in both human and physical capital that further enhance efficiency. More time must pass before any conclusions can be reached regarding whether investment decisions are being made more efficiently after restructuring. Since power plants are so long-lived, very few new additions are made each year. If California's crisis does not induce reversals of the restructuring movement, and regulators do not shut down data reporting and researcher access to detailed plant-level data, time should enable researchers to identify additional effects of restructuring.

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