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CSEM WP 111

The Efficiency of Electricity Generation in the U.S. After Restructuring

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June 2003

This paper is part of the Center for the Study of Energy Markets (CSEM) Working Paper Series. CSEM is a program of the University of California Energy Institute, a multi-campus research unit of the University of California located on the Berkeley campus.

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THE EFFICIENCY OF ELECTRICITY GENERATION IN THE US AFTER RESTRUCTURING

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June 2003

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[1]Over the past eleven years, US electric utilities have faced significant changes to their competitive and regulatory environments. The Energy Policy Act of 1992 opened access to transmission for non-utility generating plants. Then, beginning with California in 1996, nearly half the states passed and a smaller number enacted restructuring legislation that involved complete retail access. The industry restructuring is designed to enhance economic efficiency at all levels of operation, including distribution, transmission, generation and retail services. The gains are likely to be largest in electric generation because generation costs are the largest component of end-use costs and restructuring has a larger impact on generation than on other segments of the electricity industry, such as transmission and distribution, which are likely to remain more heavily regulated.

This chapter will evaluate changes in the efficiency of electric generation from restructuring. It both summarizes the current state of knowledge on the topic and serves as a roadmap for future work. In the next section, I outline many of the changes brought about by restructuring, focusing on why they might affect generation efficiency. Section 2 discusses the aspects of production that could possibly be affected. Section 3 outlines some possible approaches for measuring the effects and Section 4 discusses the existing empirical evidence. Section 5 concludes.

Section 1: Why Might Restructuring Affect Generation Efficiency?

In this section, I outline several possible effects restructuring could have on generation efficiency. I begin by describing the effect of new incentives on existing plant owners. I then consider how changes in plant ownership could affect efficiency and conclude by describing how restructuring is changing which firms are building plants.

<a> Existing Plant Owners Face New Incentives

Many investor-owned utilities began to see competition for their business before the Energy Policy Act of 1992. The Public Utility Regulatory Policy Act of 1978 (or PURPA) created a market for non-utility generators, specifically cogeneration facilities or plants using renewable resources. Also, initiatives to increase demand side management led to competitive procurement processes in several states. The Energy Policy Act gave open access to transmission lines for any non-utility generator that built a new power plant in any state. In order to remain competitive and maintain market share in the face of increasing numbers of non-utility generators, the utilities may have taken steps to reduce their operating costs and improve their operating performance. For example, in Boston Edison Company's 1993 10-K, the company discusses its responses to increased competition: "The Company is responding to the current and anticipated competitive pressures with a commitment to cost control and increased operating efficiencies without sacrificing quality of service or profitability" [p. 6].

After 1992, the most dramatic changes to the regulatory structure came through state restructuring programs, and as the 1990s progressed, more and more companies saw restructuring legislation discussed and eventually passed in their states. The middle Column of Table 1 indicates whether a state had passed restructuring legislation as of April 2001. By way of comparison, Column 2 summarizes the fraction of generating capacity in each state owned by non-utility generators as of 1995. Numbers in red indicate that non-utility generators in that state had built less than the median share (5.1%) of total capacity. States with high penetration by non-utility generators (highlighted in blue), like California, Rhode Island, and Massachusetts were also on the forefront of restructuring movements.

Restructuring has differed across states, and no one necessarily knew where it was going when it started, but I discuss several general features of restructuring programs that may change companies' incentives to operate their existing plants. Without knowing exactly what restructuring will look like, plant owners generally know that it means the end of cost-plus regulation—this is what restructuring is trying to replace. Details about what wholesale and retail markets will look like, how they will interact and how they will contribute to investor-owned utilities' bottom lines have been the meat of the debates about restructuring.

Competitive wholesale electricity markets are the starting point for restructuring programs, formalizing and broadening the competition investor-owned utilities (IOUs) face for the right to sell electricity. In a typical competitive spot market, plant owners submit daily or hourly bids to supply power. An auctioneer (e.g. an independent system operator) combines the bids into an aggregate supply schedule and intersects this schedule with a (usually vertical) demand curve to determine which units will be used to supply power. Nearly all the markets are run as uniform price auctions, so that the bid of the marginal generating unit sets the price paid to all generators who have submitted winning bids. The fraction of total transactions made through the spot markets has varied across states. California reluctantly allowed companies to sign bilateral forward contracts while in other states long-term contracts are a more important component of trading. Even with extensive contracting, contract prices and dispatch decisions should be based on expected spot market prices.[1]

The existing competitive wholesale markets are regional. Of the markets now in operation, the New England ISO is the smallest, with 2001 peak demand of 24,967 megawatts (MWs), followed by the New York ISO, with 2001 peak demand of 30,982 MWs, the California ISO, with 2001 peak demand of 41,155 MWs, Pennsylvania, New Jersey and Maryland (PJM), with 2001 peak demand of 54,030 MWs and Texas, with 2001 peak demand of 55,201. By comparison, the sum of peak demands in the US is nearly 700,000 MWs.[2]

In order to maximize the profits it earns through the wholesale market, companies want to ensure that they are operating their plants at low cost. If a plant is bid into the spot market at its marginal costs, lower costs will increase the chance that bid will be lower than a competitor's bid and the plant will increase its chances of being included in the dispatch schedule. Competing bids come from other IOUs in the region, government authorities like TVA, merchant firms operating old plants and newly constructed plants, and imports from other regions. Even if it is not bidding its marginal cost (but is exercising market power), low costs yield higher profits at the market-clearing price. Similarly, companies can maximize their profits from long-term contracts by minimizing their operating costs.

In order to assess how the new competitive wholesale markets are changing generators' incentives to minimize costs, we need to think about how the dispatch was determined before restructuring. Suppliers organized themselves into regional power pools. Some of these power pools essentially worked liked competitive wholesale markets and aggregated supplies to find the cost minimizing mix of plants to meet demand. (These pools, such as the pre-restructuring New England and PJM pools, are sometimes referred to as "tight.") Where power pools weren't as organized, bilateral short-term power purchase and sales agreements helped utilities minimize their production costs. If power pooling arrangements were able to mimic a wholesale market in finding the least expensive mix of plants to meet demand, competition to sell into deregulated wholesale markets may not have much effect on the dispatch order.

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[1] Contract prices will not equal expected spot prices if either buyers or sellers are risk averse.
[2] The figures reported in this paragraph are from several sources, including websites listed on the UC Energy Institute web page (http://www.ucei.berkeley.edu/datamine/LINKS.html) and the North American Electric Reliability Council website (http://www.nerc.com/~esd/hcapdem.xls).

What restructuring changes without question is the compensation firms receive for participating in the dispatch schedule. Under cost-plus regulation, utilities are guaranteed a service territory and regulators use reported costs to set the prices paid by the customers within the service territories. Consider an investor-owned utility that owned a cycling plant in Massachusetts and was part of the tight New England power pool. Prior to restructuring, its rates were set based on its reported costs to the regulator. Allowed fuel costs were adjusted quarterly to reflect changes in fuel procurement costs while rates were adjusted to reflect changes in operations and maintenance and capital costs during rate hearings. Given this, the company had little incentive to minimize its costs.[3] So while the power pool may have found the right mix of plants conditional on their costs, new links between costs and revenue could change firms' incentives to keep fuel, operation and maintenance and capital costs down.

Restructuring programs have changed the way retail rates are determined and the way in which retail customers are allocated. Different states have used different approaches to linking retail rates under restructuring to the wholesale prices. Most states have implemented short-term rate freezes. These decouple the link between a utility's costs and its revenue, so that now it can keep the difference between its rates and any savings it can squeeze out of its fuel costs, for instance. Some states, such as Pennsylvania, are aggressively trying to encourage entry by competitive energy suppliers to whom utilities are at risk of loosing their retail customers. A utility's net position in the spot market can affect how aggressively it bids into the market, although it still maximizes profits by minimizing the cost of the energy it does sell there.

Finally, as cost-plus regulation is replaced by less regulated wholesale markets, the political constraints faced by the plant owners change. For instance, all of the existing wholesale markets fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), so plant owners are much more beholden to federal regulators than to the local state utility commission. FERC commissioners have different constituencies and different political agendas than state commissioners.

<b> Existing Plants Owned and Operated by New Companies

[3] IOUs are not guaranteed recovery of every penny they spend for several reasons, including regulatory lag, reflecting the fact that firms' rates are fixed until the next rate hearing, selective performance programs, which tie companies' rates (often through the allowed cost of capital) to plant performance, and the threat that a regulator will disallow certain costs.

As part of their restructuring programs, a number of states have encouraged the vertically integrated utilities to sell some or all of their generating plants. Divestitures fulfill several objectives. First, by separating the ownership of generating plants from the ownership and operation of transmission assets, divestitures alleviate fears that vertically integrated companies will operate transmission in a way that biases against competing generation owners. Also, there have been concerns that restructuring might lead to stranded costs, i.e. that a plant's market value, based on prices in a restructured wholesale market, will be lower than its book value. Divestitures have been used as a means of determining the market value of assets and hence stranded costs.

Divestitures have led to a considerable turnover in plant ownership.[4] By the end of 2001, 305 plants accounting for over 156,000 MWs, or nearly 20% of US generating capacity had been transferred from utilities to merchant generators. The last column of Table 1 lists the number of plants divested in each state. Divestitures have taken place in 24 states, although most of them have been in a handful of states, including Pennsylvania, New York, Massachusetts, Illinois and California. Nearly three quarters of the capacity has been sold to merchant generators that were unregulated subsidiaries of investor-owned utilities (Ishii 2003). For instance, while Pacific Gas & Electric Company divested most of their plants in California, their merchant subsidiary, National Energy Group, purchased plants in New England.

New merchant owners can differ from IOUs on several dimensions. First, the new owners are not vertically integrated into transmission and distribution (at least in the geographic market in which they purchase capacity), so the discussion in the previous subsection about how wholesale costs are reflected in retail rates is moot. Merchant owners earn revenue by selling into the wholesale markets and earning wholesale prices. As a result, they face clear incentives to minimize costs. On the other hand, they may also face incentives to exercise market power and raise wholesale prices. As discussed in several of the chapters in this volume, market power discussions have been central to the early experiences with restructuring.

On the cost side, the capacity reshuffling may allow owners to specialize in running a particular type of plant. Vertically integrated utilities traditionally have owned enough capacity to satisfy retail

[4] Outside the US, electricity restructuring has accompanied privatization. Private companies face different incentives from government operators on a number of dimensions, but because privatizations don't factor into the US experience, I do not discuss them here.

demand in their service territory. Occasionally, a given utility will be short for a while and rely on purchases from other utilities. Nonetheless, nearly all utilities hold portfolios of baseload, cycling and peaking plants using different technologies (steam turbines, combustion turbines, combined cycle) and fuels (nuclear, coal, oil and gas). Merchant generators are no longer constrained to meet demand in a particular geographic area and can specialize in operating particular types of plants. For example, Calpine specializes in operating natural gas-fired plants, primarily baseload combined-cycle plants. In their 2001 10-K, the company claims that they can, "achieve significant operating synergies and efficiencies in fuel procurement, power marketing, and operations and maintenance" [p. 4].

<c> New Electricity Generating Plants

More important over the long run than the changes at existing plants, restructuring will change how new capacity is added to the system. By making it easier for merchant power companies to sell the power from their plants, one of the primary goals of restructuring is to take the decisions about plant investments out of the hands of rate-of-return regulated companies. Some speculate that this is the source of the major benefits that will come out of restructuring. For example, Joskow (1997) states that, "my sense is that the opportunities for cost savings in the United States in the medium run are significant, but not enormous. The most important opportunities for cost savings are associated with long-run investments in generating capacity" (p. 125).

Section 2: What Might Change?

Generators combine fuel, labor, materials and capital to make electricity.[5] A single plant's costs of producing electricity are a function of the prices and amounts of each input. For instance, from a simple cost accounting perspective, a plant's costs of producing a given number of MWhs over a year can be represented by the following equation:

$$C=P_F*F + P_L*L + P_M*M + P_K*K$$

where F, L, M and K represent fuel, labor, material and capital, respectively and P_i is the price of input $i \in \{F, L, M, K\}$ measured in dollars per whatever unit is used to enumerate the respective input. For instance, if labor inputs were measured in person-hours per year, P_L would be the average hourly wage rate. C is measured in total dollars per year. Using this equation as a starting point, this section begins by considering how restructuring might affect the amount of each input used and the prices paid for each input. The end of the section goes beyond this equation to address how restructuring might change other dimensions of production, including plant-level reliability and the mix of plants used.

<a> Inputs

A production function is a mathematical representation of the relationship between inputs and outputs. It can be used to define a production frontier, which defines the maximum possible output for any given combination of inputs. If a firm is fully using its inputs, it is on the technology or production frontier. An electric utility would *not* be on the technology frontier if, for instance, it were buying too many spare parts and they were lying around and not contributing to the production of electricity.

Production functions describe the technological process of transforming inputs to outputs and ignore the costs of the inputs. Cost minimization assumes that, given the input costs, firms choose the mix of inputs that minimizes the costs of producing a given level of output. A firm could be on the production frontier, but not minimizing its costs if, for instance, labor was cheap relative to materials, yet a firm were using a lot of materials. Given the number of workers it was hiring and the amount of materials it was buying, it could have been producing the most possible output, but it may have been able to produce the same level of output less expensively by substituting labor for materials.

This framework helps us think about how new incentives might change the way companies produce electricity. In the face of new incentives, there are several general areas where new owners or old owners with new incentives might change their practices. Firms facing more competition might move closer to the technological frontier by figuring out how to generate the same amount of electricity with fewer inputs.[6] For example, impending restructuring may give utility management a bargaining chip they can use with unions to consolidate jobs at plants. For plants that are divested, the sales may be a way to break or weaken the union and eliminate jobs. Also, under cost-plus regulation, fuel adjustment clauses

[5] This is of course a simplification, and one could imagine other ways to categorize the inputs to electricity generation (distinguishing environmental inputs, for instance).
[6] I am assuming that restructuring did not change the production function.

allow utilities to pass through to ratepayers all of their fuel costs, so they have little incentive to minimize the amount of fuel they burn to generate a given amount of electricity.[7]

On the other hand, new owners could at least temporarily require more inputs per MWh if intangible knowledge about running the plants cannot be transferred with the transfer of ownership. These losses might be avoided if the knowledge is embodied in the old workers and the new owners correctly value keeping them on the payroll. Similarly, restructuring may inhibit plant owners from sharing information with one another about best practices, so that the diffusion of knowledge about how to operate plants optimally may be slowed.

To minimize the cost of producing a given level of output, a firm must also find the right mix of inputs given their relative costs. The ability of a firm to change the mix of inputs in response to factor prices is a function of how substitutable inputs are. For instance, if labor prices go down, a profit-maximizing plant owner may be able to hire more workers who can do maintenance to achieve lower heat rates at his plant (hence burning less fuel), but beyond a certain point, labor can no longer substitute for fuel.[8]

One noteworthy example of how restructuring might change the mix of inputs is suggested by the Averch-Johnson effect, which describes how rate-of-return regulation can bias companies in favor of capital-intensive projects (Averch and Johnson 1962). For one, regulated companies may be over-using capital at specific plants. It is also possible that rate-of-return regulation has distorted traditional investor-owned utilities' incentives to invest in the proper mix of generating plant technologies. Investments in nuclear power projects during the 1970s and 1980s, which frequently far exceeded their initial capital budgets, exemplify this notion.

<b> Price of Inputs

Restructuring may permit utilities to lower the costs at which they procure some inputs. For labor costs, there is evidence from other formerly regulated industries that union wages fall after deregulation (Rose 1987). Older work specific to the electricity industry, however, finds that average wage levels for

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[7] See Baron and DeBondt (1979) for a theoretical treatment of the efficiency characteristics of fuel adjustment clauses and Gollop and Karlson (1978) for an empirical analysis.

[8] Several papers report estimates of cross-price elasticities (e.g. by how much demand for labor increases when the price of fuel increases), and while the estimates vary considerably, they all suggest that fuel, labor and materials are substitutes to some degree (see Christensen and Greene, 1976 or Kleit and Terrell, 2001).

electricity workers are lower than wages for comparable workers in unregulated industries (Hendricks 1975, 1977).

For fuel costs, fuel adjustment clauses leave utilities little incentive to minimize the prices they pay for their fuel. As a result, utilities may overpay for flexible delivery schedules and they may not take advantage of financial instruments to help them minimize their costs. Also, sometimes environmental compliance costs (e.g. permits) are included with fuel costs, so utilities may not take every possible step to minimize these costs. Hence, after restructuring utilities may pay lower fuel and environmental prices.

As more non-utility generators build and operate plants, the prices at which plant owners acquire capital may also change. Also, restructuring may change the rates at which utilities themselves can acquire capital. Because rate-of-return regulation all but guarantees that utilities cover their costs, they have traditionally been able to borrow money at low rates. Since non-utility generators' revenues are more at risk, investors demand higher returns. This affect is mitigated to the extent that non-utility generators can sign long-term contracts to insulate their revenue streams from adverse shocks.

To the extent that the relative levels of prices change (e.g. capital costs increase while labor costs fall), profit-maximizing plant owners will adjust the level of inputs they use, providing another reason why the level of inputs, discussed in the previous subsection, may change with restructuring.

<c> Timing of Production—Preventative Maintenance and Forced Outages

Relaxing the assumptions embedded in the above framework highlights other possible changes to electricity production. For instance, the above discussion assumes that utilities are producing one output—megawatt-hours. Because electricity is non-storable, however, it makes more sense to think of electricity produced at 5PM in July as a separate output from electricity produced at 5AM in March. For a given plant, therefore, we care not only about how much electricity it produces but also when it produces it. Firms must decide how to balance the costs associated with taking their plant down to do maintenance against the probability that a poorly maintained plant will fail during peak demand hours. It is likely that changes in incentives associated with restructuring change firms' assessments of the proper tradeoff, although there are explanations that suggest plant owners would do more or less preventative maintenance after restructuring.

For instance, under cost-plus regulation, utilities may face strong political incentives to avoid blackouts or brownouts. They may do this both by overbuilding to maintain high reserve margins and by investing heavily in maintaining the reliability of their plants for times of peak demand. Unlike firms in restructured markets, regulated firms can pass on their maintenance costs to ratepayers. On the other hand, firms producing in restructured wholesale markets may face even stronger incentives to be available when demand peaks because this is when prices are highest. (If a firm has market power, however, it may not be optimal to have all of its capacity available even when demand levels are highest.) In order to determine the optimal balance between scheduled outages for preventative maintenance and the probability that a plant fails down the road, a firm would need to form expectations about the costs of a scheduled outage, primarily foregone wholesale market profits in a restructured market.

<d> Market Power

The above discussion has focused on changes in production processes at a given plant. Several of the changes associated with restructuring may change inter-plant or even inter-firm efficiency. First, the restructured wholesale electricity markets have typically been dominated by a handful of large "strategic" sellers who face incentives to withhold capacity in order to boost the market price. Other sellers have less of an incentive to withhold capacity either because they are too small or because they are government-owned firms (*e.g.* Bonneville Power Administration) that do not have a clear profit-maximizing incentive. These so-called "fringe" firms are thought to sell power as long as the market price exceeds their cost. When the large, strategic firms withhold capacity and drive up the price, less efficient fringe plants find it profitable to produce. If the fringe firms' plants are less efficient than the strategic firms' plants that are withheld, the overall cost of electricity production can go up (see Borenstein, Bushnell and Wolak 2002 and Mansur 2001). Because of transmission congestion, firms may also exercise market power by withholding capacity from plants in specific locations (Borenstein, Bushnell and Stoft 2000 and Joskow and Tirole 2000).

<e> System-wide Investments

The Averch-Johnson effect, described above, provides one explanation for why the overall mix of plants on the system may change with restructuring. If the Averch-Johnson effect causes utilities to over-invest in capital-intensive technologies at the plant level, the mix of plants brought online may change with restructuring. Also, if wholesale prices are high because firms are exercising market power, there may be too much new capacity built. This is because firms are building new plants to supply power that could have been supplied by existing plants in the market had firms not withheld the capacity to exercise market power. Also, Borenstein and Holland (2002) explore the relationship between the structure of retail prices and capacity investment. The start with the observation that in all restructured markets almost all customers still pay a flat per kWh rate that does not reflect real time changes in the wholesale price. They point out that there will always be over-investment in capacity relative to the first-best outcome with all customers on real-time prices. This occurs because customers who pay a flat rate, representing a weighted average of the time-varying (e.g. hourly) wholesale prices, are paying too little and over-consuming during peak periods when there is little excess capacity. They also show that competitive markets do not even achieve the second-best optimum that could be achieved through a specific form of cost-of-service regulation.

<f> Increased Coordination across Plants

One of the main motivations for electricity industry restructuring is the observation that current generating plant technologies take advantage of economies of scale, and have for some years (Joskow and Schmalensee, 1983). As discussed above, the fact that merchant firms buying divested plants seem to be specializing by plant type suggests that there may be further economies of scale at the firm level. In addition, the FERC appears to believe that regional coordination across firms has been incomplete, and that significant gains are possible through improvements in pricing, congestion management, estimates of available transmission capability and planning. For instance, a cheap plant in Montana may have excess generation capacity while a more expensive plant in California runs because there is incomplete coordination between the owners in Montana and California. FERC's approach so far has been to improve market institutions through Regional Transmission Organizations rather than to encourage geographic consolidation within firms. For instance, the Notice of Proposed Rulemaking on Standard Market Design, the FERC's roadmap to competitive markets states:

The fundamental goal of the Standard Market Design requirements, in conjunction with the standardized transmission service, is to create "seamless" wholesale power markets that allow sellers to transact easily across transmission grid boundaries and that allow customers to receive the benefits of lower-cost and more reliable electric supply. For example, currently a supplier that seeks to serve load in a distant state may need to cross several utility systems or independent system operator systems (ISOs), all of which have different rules for such things as reserving and scheduling transmission and scheduling generation. This can either result in an efficient transaction not occurring at all or it can add significant time and costs to the transaction. Standard Market Design seeks to eliminate such impediments. [p. 6-7, §11]

Section 3: How Should We Measure These Effects?

The previous section delineates several possible ways in which electricity generation efficiency could change with restructuring. On some of these issues, we already have some evidence, which I will discuss in the following section. The researchers who set out to obtain convincing empirical evidence on each of these issues face their own unique issues, although there are some common challenges that I lay out in this section.

<a> Empirical Strategies

To determine empirically how restructuring has changed electricity generation, we need to come up with a counterfactual description of generation efficiency in the absence of restructuring. For the sake of exposition, assume we are trying to assess how restructuring has changed staffing at plants that are still owned by investor-owned utilities (*i.e.* at non-divested plants).[9] To answer this question, we need an estimate of staffing levels in the absence of restructuring. One obvious estimate is staffing levels prior to restructuring. We could evaluate whether staffing levels have fallen since 1992 and whether, perhaps, the rate of decline picks up as states construct and adopt their individual restructuring programs. Since, however, many other things change over time (such as information technology that makes staff obsolete or the power of unions to keep jobs), we would be confounding improvements over time that are independent of restructuring with the effects of restructuring.

Ideally, one would like to find a control group of plants with similar characteristics (fuel type, capacity, etc.) that experience exactly the same changes in unionization, technology exposure, etc. as plants in the US faced with restructuring, but are not themselves exposed to restructuring initiatives. Then, one could compare changes in staffing before 1992 at the control plants to changes at the plants facing

[9] Markiewicz, Rose and Wolfram (2003), which I discuss in Section 4, examines this question.

restructuring. The difference in these two changes most likely reflects the effects of restructuring. (This approach is often referred to as "difference-in-differences.") There are several possibilities for control groups, although each has its own sets of problems. For instance, if data were available, one could use plants in countries that are not currently restructuring as a control group. If, however, changes in unionization are driving changes over time in the US but not abroad, this could be confounded with restructuring. Plants owned and operated by municipalities provide another potential control group to the extent that restructuring initiatives leave their incentives to minimize plant costs unchanged.

Another possible approach is to compare plants in states where restructuring is progressing quickly to states where it is moving more slowly with the hypothesis that utilities that do not see restructuring on their near-term horizon will be less likely to enact changes to their existing practices. Plants in the states where restructuring is moving slowly serve as the control group to pick up the effects of other changes in the US over time. As mentioned above, as of April 2001, 24 of the 48 states had passed restructuring legislation. This approach is likely to underestimate the effects of restructuring since any changes due to restructuring in the slow states will be unmeasured. There are several reasons to expect employee reductions to begin as soon as managers see restructuring on the horizon (e.g. as soon as the state legislature passes a restructuring bill). First, there are a number of changes that take time to enact, so even if utilities had no immediate incentive to reduce their costs, they may have taken steps to do so immediately. For instance, if employment reductions are to be done through attrition rather than layoffs, this will take time. Second, if they anticipate that they will be selling plants, they may improve efficiency to make the plant look more attractive to potential buyers. Third, even before full retail access, utilities in some states were facing significant competition from non-utility generators (see the first column of Table 1).

Also for specific questions, it is possible to take advantage of other cross-sectional differences. For example, to evaluate whether changes in staffing levels depended on the political constraints faced by IOUs under regulation, one could assess whether changes in staffing varied across states where the public utility commission was more or less sympathetic to investor interests.[10]

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[10] In Joskow, Rose and Wolfram (1996), we use measures of state commissions' attitudes towards investors to assess political constraints on executive compensation at IOUs.

Rather than using data from a control group to model the counterfactual outcome, one could also develop a model of the industry pre-restructuring, simulate its progression through the 1990s and early 2000 and then compare actual developments to what actually happened. This is the approach taken by Newbery and Pollitt (1997) to assess the impacts of electricity industry restructuring and privatization in the UK. Also, Ishii and Yan (2002) take this approach to study investment decisions by independent power producers. The advantage of this approach is that it does not rely on constructing a control group. The disadvantage is that it relies on having a good model of the industry that captures the important forces.

The difficulties associated with describing a counterfactual are compounded for long-run investment decisions. First, we have to wait several years since the investment life cycle of plants is so long. Even after we have had several years to put merchant investors' power plant investment decisions to market tests, however, it will be difficult to assess whether they have made "better" decisions than utilities would have. This requires constructing a counterfactual description of what utilities would have built facing the same set of fuel price projections, environmental regulations, etc.

<b> Available Data

There are broadly four categories of data available to answer the types of questions raised in this chapter: (1) data collected under cost-plus regulation, (2) data available from the existing competitive wholesale electricity markets, (3) data collected by environmental regulators, and (4) data from other sources.

One nice aspect of cost-plus regulation is that regulators collect detailed data on costs, including output and inputs. For instance, the FERC requires every utility to file annual operating and financial information in their FERC Form 1. The data include operating statistics such as fuel usage, number of employees, non-fuel operating expenses, total capacity factor, and many other firm and plant level statistics. FERC has very clear and explicit reporting standards for this form, so subjective reporting differences between companies and across time should be minimized. Also, the FERC (formerly the Federal Power Commission) has collected data since it was created in 1935, so some trends can be tracked over a number of years. In addition to the FERC, several regulatory agencies collect data including the state public utility commissions (some of the information collected at the state level is aggregated by the

National Association of Regulatory Utility Commissioners—NARUC), the Energy Information Agency (part of the Department of Energy), and the Nuclear Regulatory Commission for nuclear electric plants.

All of the existing competitive wholesale electricity markets have released publicly information on prices and total quantities transacted. Information on individual bidder's participation in the markets (e.g. their bids or their scheduled output) has generally been protected. Some markets have decided to release plant-or firm-specific bid curves that mask the identities of plants and bidders, although researchers have used other data to back out the firms' identities (Barmack 2003).

Because electricity producers are significant polluters, environmental compliance costs can comprise a significant component of their input costs. Unfortunately, environmental regulation is fragmented, so getting a handle on the costs for a given plant can involve collecting data from several regulatory bodies. For instance, plants in PJM are subject to the Environmental Protection Agency for SO_2 regulations and the Ozone Transport Commission NO_x regulations. Fortunately, in the process of collecting information for environmental compliance, the Environmental Protection Agency collects hourly data on the fuel consumption and output of most fossil fuel-burning generating units in the country through their Continuous Emissions Monitoring System (CEMS) database. Information on inputs and outputs allows one to construct a generating unit's heat rate, one measure of short run operating efficiency. This provides a rare level of detail on the production process.

In addition, as with any other firm or industry, data are available from Securities and Exchange Commission filings, stock market prices, and debt rating agencies.

Section 4: What Do We Know Already?

This section discusses several pieces of evidence that speak to the size and importance of the various effects discussed so far. Using the framework developed above, I first consider changes to variable costs (prices for and amounts of fuel, labor and materials) and capital costs (interest rates and capital expenditures).[11] For variable costs, I first discuss the effects of the new incentives faced by the utilities, then the effects of new ownership. The subsection on capital costs discusses these two effects but focuses on the effects of having new firms building new plants.

<a> Variable Costs

<i> *CHANGES AT EXISTING PLANTS BY IOUS:* A series of papers have used data on electric generating plants to estimate cost frontiers (see, for example, Christensen and Greene 1976; Greene 1990 and Kleit and Terrell 2001). These give us some clues about how technical efficiency varies across plants, and thus some indication of possible improvements. One view is that restructuring will push most plants to the frontier. Since the frontier is defined by observations on plants under cost-plus regulation, it is also possible that even the most efficient plants have room for improvement and that efficiency will improve by more than the measured inefficiency. The results suggest that under cost-plus regulation, the average plant could reduce costs by 10-15% by producing efficiently. Similarly, Joskow and Schmalensee (1987) find that firms appear to be better and worse at operating coal-burning power plants.

Newbery and Pollitt (1997) study the effects of the privatization and restructuring of the electricity sector in the United Kingdom. Among other things, they document significant labor force reductions, although it is impossible to disentangle the extent to which this was a result of privatization as opposed to restructuring.

On the price side, electricity is the latest of a series of formerly regulated industries to go through a radical restructuring, including airlines, trucking, and telecommunications. In all of these industries, restructuring has led to wage reductions for at least some categories of worker (see Fortin and Lemieux, 1997 and Joskow and Rose 1987). In some industries, the wage reductions accompanying deregulation have been substantial. Rose (1987) finds that the union wage premia declined from 50 percent over non-union wages to 30 percent over non-union wages following deregulation of the trucking industry in the late 1970s. Early work by Hendricks (1975, 1977), however, suggested that electric utility workers earned less than their counterparts with similar job descriptions in other unregulated industries. It should be noted that while wage reductions may eventually lead to a better allocation of skilled workers across industries, the immediate effect of wage reductions is not an efficiency enhancement but rather a rent transfer from workers back to customers. No work, of which I am aware, has considered the effects of deregulation on a factor price other than labor.

In ongoing work with several co-authors, I am directly measuring whether existing plant owners have changed the amounts and prices of some inputs in response to restructuring discussions in their state

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[11] Note that fuel, labor, materials and capital account for roughly 55%, 8%, 22% and 15% of generating

(Markiewicz, Rose and Wolfram, 2003). As noted above, restructuring initiatives have progressed at different paces in different states. We take advantage of this variation to compare how owners faced by more imminent restructuring have changed their operating practices compared to owners of plants in states where restructuring has seemed less likely. We separate states into two groups, *Restructuring States* and *Non Restructuring States*, based on whether they passed restructuring legislation as of April 2001. We compare operating statistics across these groups using plant-level data from the FERC Form 1s from 1981-1999.[12]

Figures 1-3 compare employees per megawatt, nonfuel expenses per megawatt and fuel (coal) expenses per megawatt-hour at plants in *Restructuring States* to plants in *Non-Restructuring States*.[13] The pattern in Figures 1 and 2 is most stark. Beginning in the early 1990s, plants in the *Restructuring States* reduced their employment levels and non-fuel operating expenses relative to plants in *Non-Restructuring States*. While average employment levels have been falling nearly every year since 1981, they began to fall faster at plants in *Restructuring States* beginning in 1993. Average non-fuel operating expenses have risen nearly consistently in *Non-Restructuring* States, while in *Restructuring States* they began to fall in 1992. Notably, the first state-level initiatives to introduce restructuring occurred in late 1993 and 1994, when public utility commissions in California, Connecticut, Massachusetts and Rhode Island began formal debates about restructuring initiatives. The results in Figure 3 are less striking, though in our regression analysis, we analyze fuel inputs and fuel prices separately and find that there is a slightly larger reduction in coal prices at plants in *Restructuring States.*

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costs, where capital here is defined as included in the rate base.

[12] Plants are associated with the state in which they are regulated. A company may own a plant located in one state yet have its exclusive service territory in a different state, and that second state is the state by which we measure the restructuring policy. Some plants are owned by a company with service territories in more than one state and some plants are owned by several companies that are regulated by different states. This creates a potential problem for allocating the plants to a particular state's deregulation policy. In separate analyses, we treat these two groups of plants independently. Our results from those analyses suggest that these issues are not affecting the differences between *Restructuring States* and *Non-Restructuring States* depicted in the figures.

[13] This analysis assumes that firms have rational expectations regarding whether or not restructuring legislation will be passed. Plants regulated by states that did initiate formal proceedings at some point in time, but did not (as of April 2001) pass legislation, are assumed to experience no influence from restructuring. Since states that have not yet passed the law are unlikely to do so for several years due to the problems experienced in California, this assumption is fair. Some states that did pass a restructuring law are in fact reconsidering the policy in light of the recent difficulties.

In Markiewicz, Rose and Wolfram (2003) we find that the patterns depicted in Figures 1-2—greater reductions in employment and non-fuel operating expenses at plants in *Restructurin*g States—persist when we use regression analysis to control for both time invariant plant characteristics using plant fixed effects and for time-varying plant characteristics (including capacity factors, changes in nameplate capacity and the presence of environmental control technology). In addition, the regression analysis allows us to differentiate across *Restructuring States* based on the year in which restructuring initiatives began. Generally, our results suggest that employees per megawatt fell by approximately 8% and non-fuel operating expenses per megawatt fell by approximately 14% following the initiation of restructuring discussions. These input reductions appear to have negatively impacted these plants' output, although we continue to investigate by how much.

To translate these percentage reductions into changes in costs, we need to make several assumptions. First, at the average plant in our database (750 MWs), a 14% reduction translates into non-fuel expense savings of $2.3 million per year and an 8% workforce reduction amounts to 15 employees. If total costs per employee (wages plus benefits) are $60,000, this translates into nearly $1 million. To scale this up to the industry level, note that there are nearly 800,000 MWs of capacity in the US. If every plant in the US could achieve these savings eventually, industry costs would fall by $3-$4 billion.[14]

Several caveats are necessary. These are short-run effects and it is possible that the efficiency gains could be reversed over the long run if there are reductions in knowledge sharing that affect productivity gradually over time. It is also possible, however, that longer run effects will be more striking as firms with new incentives make investments in both human and physical capital that pay off over time. Also, as mentioned above the price reductions are most likely simply transfers, not changes in efficiency.

One significant problem with the data set used to create Figures 1-3 is the lack of data on plants purchased by merchant generators because they are not required to file the FERC Form 1. Merchant generators purchase existing generating capacity, often the plants that incumbents were required to divest during restructuring, and build new capacity. A potential selection problem would be of concern if the plants being purchased were either less or more efficient than other plants. One might expect that plants utilities knew they would divest were run differently before the divestiture. All regressions were also run excluding plants that did not have data through 1999 and results were consistent with those depicted in the Figures.

<*ii*> *CHANGES AT EXISTING PLANTS BY NEW OWNERS:* In Bushnell and Wolfram (2003), we investigate whether plants divested to merchant generators perform differently after the divestiture. We use information from the Continuous Emissions Monitoring System (CEMS) database collected by the Environmental Protection Agency. The CEMS data are collected for all fossil-fueled power plant units that operate more than a certain number of hours a year. The dataset contains hourly reports on heat input, electricity output and pollutant output. The data provide a much finer picture of plant operations than the annual FERC Form 1 data, although they lack the comprehensive information on non-fuel inputs and fuel expenditures and they are only available beginning in the last quarter of 1997. We analyze the data through December 2001.

We matched the CEMS data to information on divestitures taken from the, "Electric Utility Plants That have Been Sold and Reclassified as Nonutility Plants" table in the Energy Information Administration, *Electric Power Monthly*, March (various years). As of December 2001, divestitures have taken place in 24 states (see the last column of Table 1).

We used the CEMS data to construct hourly heat rates, a measure of the heat input (measured in British Thermal Units) used to generate a megawatt-hour of electricity. Table 2 reports changes in the average heat rates at plants that were divested before and after the divestiture (columns (1) and (4)) and before and after the divestiture compared to plants in the same states that weren't divested (columns (2) and (5)).[15] We report the results separately for plants divested in *Market States*, which we define as states that had developed restructured wholesale markets by December 2001, and plants divested in *Non-Market States*. We do this because we believe that plants may be operated differently in states with markets, for example because of the incentives to exercise market power. We also report results at five different points

[14] This calculation assumes nuclear plants could achieve the same reductions, although since our data set does not include nuclear plants, we have not analyzed them.

[15] The reported results are based on regression specifications with unit-quintile fixed effects. For the results in Columns (1) and (4) the specification only included plants that were divested at some point over the time period we analyze and the reported changes are based on the coefficients on dummy variables equal to one after the divestiture (since our dependent variable is the log of the heat rate, we report the exponent of the coefficients minus one). The results in Columns (2) and (5) include both divested and non-divested plants as well as month-year-state fixed effects.

on the unit's heat rate curve to assess whether the impact of divestitures is different at different operating levels.

The results suggest that plant heat rates improve (come down) after divestitures, and the results are particularly robust for divestitures in the *Market States*. They suggest that when plants are operating at 40-100% of their capacity, plant heat rates come down by 2-2.5% following the divestiture. To put a dollar figure on this reduction, consider that for a plant with a heat rate of 10,000 btu/kwh buying fuel for $4 per mmbtu (current natural gas price forecasts estimate $3-$4 per mmbtu), this implies a reduction of $1 per MWh. Columns (3) and (6) of Table 2 demonstrate that over 90% of the energy is generated when plants are operating above 40% of their capacity. Given that total generation in the US was 3.7 billion MWhs in 2002, if every plant in the US could achieve similar heat rate improvements, this would amount to savings of about $3.5 billion annually. This calculation assumes that divested plants were selected randomly from the population of US plants and were not, for instance, particularly ripe for improvements. Also, because of data limitations, our study does not look at whether reductions in fuel use were achieved by increasing other inputs. At least anecdotally, however, there is evidence that the divested firms reduced labor inputs.

<b> Capital Costs

Results in several papers suggest that rate-of-return regulation led to inefficient investment. For instance, a number of papers have found empirical support for the Averch-Johnson effect, including Courville (1974) and Spann (1974), although the regulatory climate considered by these papers (specifically the allowed rates of return and the willingness of commissions to disallow assets) was quite different from the one over the past twenty years.

Another way to quantify the potential reductions in capital investment levels with restructuring is by looking at investments that were disallowed by state commissions. These were investments that the utilities expected to be able to pass on to ratepayers but which state commissions judged were not "prudently incurred" or were not "used and useful." If merchant power companies will avoid such "mistakes" (as defined ex post by state commissions), the disallowances provide a measure of the potential savings in capital investment levels. Between 1980 and 1991, commissions disallowed $18.3 billion in nuclear plant costs and $782 million for coal and other plants (Lyons and Mayo, 2000). Notably, over $4 billion of the $18 billion in nuclear disallowances were attributable to two plants, the Diablo Canyon plant in California and the Nine Mile Point 2 unit in New York (see Lyons and Mayo, 2000). $19 billion over twelve years amounts to roughly $1.6 billion per year, or 5-10% of annual investment in generation. If investments in nuclear power represented idiosyncratic mistakes made once by utilities during the 1980s and unlikely to be made now that most new plants use combined cycle gas turbines, this measure overstates the likely savings going forward.

It is also instructive to think about the extent to which restructuring could affect the price of capital to firms building new plants and making capital improvements to existing plants. As Table 4 in Joskow (2003) points out, most merchant generating firms currently have below investment grade credit ratings. This is not true for most utilities. There is currently a 6 percentage point spread in yields on 10-year utility bonds with a mid-level investment grade rating (A) compared to bonds with a rating just below investment grade (BB+).[16] This may overstate the difference in the overall weighted average cost of capital between utilities and merchant firms since utilities have less debt and more equity.

To assign a dollar value to the higher borrowing rates, we need to make an assumption about the level of investment. Over the past 6 years, there were on average 25,000 megawatts added in the US per year (see Table 2 of Joskow, 2003). Assuming an approximate cost of $.5 million per megawatt, this represents $12.5 billion in investments per year. If the cost of capital for this $12.5 billion is 6 percentage points higher, capital costs will be higher by nearly $1 billion per year. Since the assets are long-lived, however, this number escalates as merchant firms build more each year. In the long-run, however, once the regulatory uncertainty gets resolved and the recent trading scandals have blown over, it is hard to see how merchant firms would continue to be rated so low. In fact, as recently as 2001, more than half the firms had investment-grade ratings. Similar to the case with the wage reductions, however, most of the increased capital costs reflect a transfer from creditors to customers rather than inefficiency. Rate of return regulation requires utility customers to pay for assets even if, for instance, demand is lower than expected and the asset is not used. With deregulated wholesale markets, however, creditors must bear the costs of an unused asset in the event of a default.

<c> Dispatch Efficiency

[16] See http://www.bondsonline.com/asp/corp/spreadbank.html (accessed May 30, 2003).

Two papers have used data on existing wholesale markets to measure the production inefficiencies that arise when some suppliers withhold capacity to exercise market power. Production inefficiencies arise because more expensive fringe plants run to replace the withheld power. Borenstein, Bushnell and Wolak (2002) consider the California market from June 1998 to October 2000. They estimate efficiency losses of $44 million in 1998, representing 2.6% of the total payments for wholesale electricity or a 3.4% increase over what total payments would have been had the market been perfectly competitive. For 1999 and 2000, the figures grow to $65 million and $347 million, respectively, representing 3.2% and 3.9% of the total payments or 3.8% or 7.1% increases over total payments estimated from a stylized competitive dispatch.

Using a slightly different approach, Mansur (2001) estimates higher production inefficiencies in PJM. His calculations suggest that production inefficiencies amounted to$160 million in the summer of 1999, or approximately 7.6% of total payments for electricity.

FERC and other organizations have commissioned a handful of studies to measure the potential benefits of some aspect of restructuring (see, for example, Department of Energy 2003, ICF Consulting 2002). While the studies typically discuss several potential benefits of restructuring, the main analytical work in them is to simulate the benefits of improved coordination through Regional Transmission Organizations by measuring trades that could have been made but were not under the current system. For instance, in a report prepared for the FERC, ICF Consulting used information on every generating unit connected to the transmission grid to simulate cost savings from increased interregional trading.[17] Their results suggest that savings could amount to $1-10 billion per year. The simulations do not account for some important aspects of wholesale market operations such as the potential for plant owners to exercise market power.[18]

Section 5: Conclusions

The California electricity crisis of 2000-2001 has slowed down restructuring initiatives in the US. Also, it has focused attention on fixing market design and market structure issues believed to be at the root

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[17] The report is available at http://www.ferc.fed.us/Electric/RTO/mrkt-strct-comments/rtostudy_final_0226.pdf.

[18] These studies take a different approach to quantifying the effects of restructuring than I have described in this chapter. Essentially, they take a "top-down" approach by plugging a number of assumptions into a big model. What I have described is more of a "bottom-up" approach that involves a number of analyses of detailed questions. The approaches are not mutually exclusive, and ideally, the results from studies like I have described could be used to enhance the assumptions used in the simulations.

of the crisis. As we step back to assess the path restructuring is taking, it is useful to remind ourselves of some of the potential economic efficiency gains from restructuring. This paper lays out a framework for considering the potential changes to electricity generation efficiency. While some of the problems with competitive wholesale electricity generation markets highlighted by the California electricity crisis, such as market power, also have negative impacts on generation efficiency, this paper has outlined a number of possible avenues through which we could see gains in efficiency.

This paper focuses on changes to generation. Although transmission and distribution costs will continue to be subject to more heavy-handed regulation than generation, moves to introduce incentive-based regulation could also yield efficiency gains.

It would be convenient to have a single number to point to as the likely changes in generation costs from restructuring. Unfortunately, the body of empirical evidence is still too sparse to even be able to speculate about the bottom line. In addition, the path of restructuring is still being laid. The studies I outlined in Section 4 suggest that investor owned utilities have reduced their generating plant staff, operations and maintenance budgets and fuel expenditures and that plants divested to merchant generators experience small improvements in their heat rates. This chapter intends to serve as a roadmap for policy makers and future researchers so that the remaining gaps in the empirical literature can be filled.

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Table 1: Changes to Investor-Owned Utilities Regulatory and Competitive Environment by State

State	Fraction of Generating Capacity Owned by Non-Utility Generators as of 1995	Restructuring Legislation Passed as of April 2001?	Plants Divested as of December 2001
Alabama	4.6	No	0
Alaska	13.8	No	1
Arizona	1.0	Yes	0
Arkansas	4.5	Yes	0
California	20.3	Yes	29
Colorado	9.7	No	0
Connecticut	9.3	Yes	14
Delaware	7.5	Yes	7
District of Columbia	0.3	Yes	2
Florida	9.7	No	1
Georgia	5.8	No	0
Hawaii	33.5	No	0
Idaho	15.6	No	0
Illinois	2.1	Yes	37
Indiana	3.5	No	2
Iowa	3.8	No	0
Kansas	0.5	No	0
Kentucky	0.0	No	5
Louisiana	14.5	No	2
Maine	36.7	Yes	4
Maryland	3.2	Yes	19
Massachusetts	16.7	Yes	31
Michigan	12.2	Yes	0
Minnesota	6.7	No	0
Mississippi	5.1	No	0
Missouri	0.7	No	0
Montana	2.5	Yes	14
Nebraska	0.2	No	0
Nevada	12.7	Yes	0
New Hampshire	9.0	Yes	4
New Jersey	19.1	Yes	27
New Mexico	3.4	Yes	0

New York	15.7	Yes	33
North Carolina	8.2	No	0
North Dakota	0.8	No	0
Ohio	1.2	Yes	2
Oklahoma	5.8	Yes	0
Oregon	3.9	Yes	0
Pennsylvania	7.3	Yes	60
Rhode Island	54.8	Yes	1
South Carolina	2.3	No	0
South Dakota	0.0	No	0
Tennessee	3.5	No	0
Texas	12.2	Yes	0
Utah	2.7	No	0
Vermont	6.2	No	4
Virginia	19.5	Yes	3
Washington	4.4	No	2
West Virginia	3.8	No	1
Wisconsin	5.0	No	0
Wyoming	1.6	No	0

Sources:
Column 1—The numerator is taken from Energy Information Administration, *Electric Power Annual, Volume II*, 1995, Table 55. The denominator is the numerator plus utility capacity from Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1996*, Table 17. Blue indicates the state has greater than median (5.1) NUG capacity.
Column 2—Various Energy Information Administration and National Association of Regulatory Utility Commissioners publications and state public utility commission websites. See Markiewicz, Rose and Wolfram (2003) for more details. "Yes" highlighted in blue.
Column 3—Energy Information Administration, *Electric Power Monthly*, March (various years), "Electric Utility Plants That Have Been Sold and Reclassified as Nonutility Plants." Blue indicates one or more plants were divested in the state.

Table 2: Average Change in Plant Heat Rates at Divested Fossil-Fuel Power Plants

	Market States[1]			*Non-Market States*[2]		
	Change After Divestiture	Change After Divestiture Compared to Non-Divested Plants	Share of Total Output[3]	Change After Divestiture	Change After Divestiture Compared to Non-Divested Plants	Share of Total Output[3]
	(1)	(2)	(3)	(4)	(5)	(6)
When plant is operating at:						
0>-20% of full capacity	2.6%*	1.1%	1.7%	-13.7%*	-9.5%	.2%
20>-40% of full capacity	.1%	-.7%	5.3%	-2.7%	<.1%	2.8%
40>-60% of full capacity	-2.0%**	-2.3%**	11.0%	-3.3%**	1.2%	10.8%
60>-80% of full capacity	-1.9%**	-2.1%**	20.6%	-1.4%	2.7%	22.4%
80>-100% of full capacity	-2.6%**	-2.0%*	61.3%	-1.2%	-.2%	63.4%
Number of observations (plants)	6,119,170 (121)	11,379,393 (304)		1,295,666 (19)	10,046,940 (149)	
Number of observations (plants) with divestitures	2,767,362 (121)	2,767,362 (121)		569,611 (19)	569,611 (19)	

** indicates that the difference is statistically significant at the 1% level based on a test that accounts for serial correlation within a plant quintile.
* indicates that the difference is statistically significant at the 5% level based on a test that accounts for serial correlation within a plant quintile.
[1] Market states are those states where divestitures have taken place that also had restructured wholesale markets as of December 2001: California, Connecticut, DC, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island, Vermont and West Virginia.
[2] Non-market states are those where divestitures have taken place where no restructured wholesale market had been set up as of December 2001: Illinois, Indiana, Kentucky, Montana, Ohio, Virginia, and Washington.
[3] Share of total output by quintile for all plants (divested and nondivested).
Source: Bushnell and Wolfram (2003).

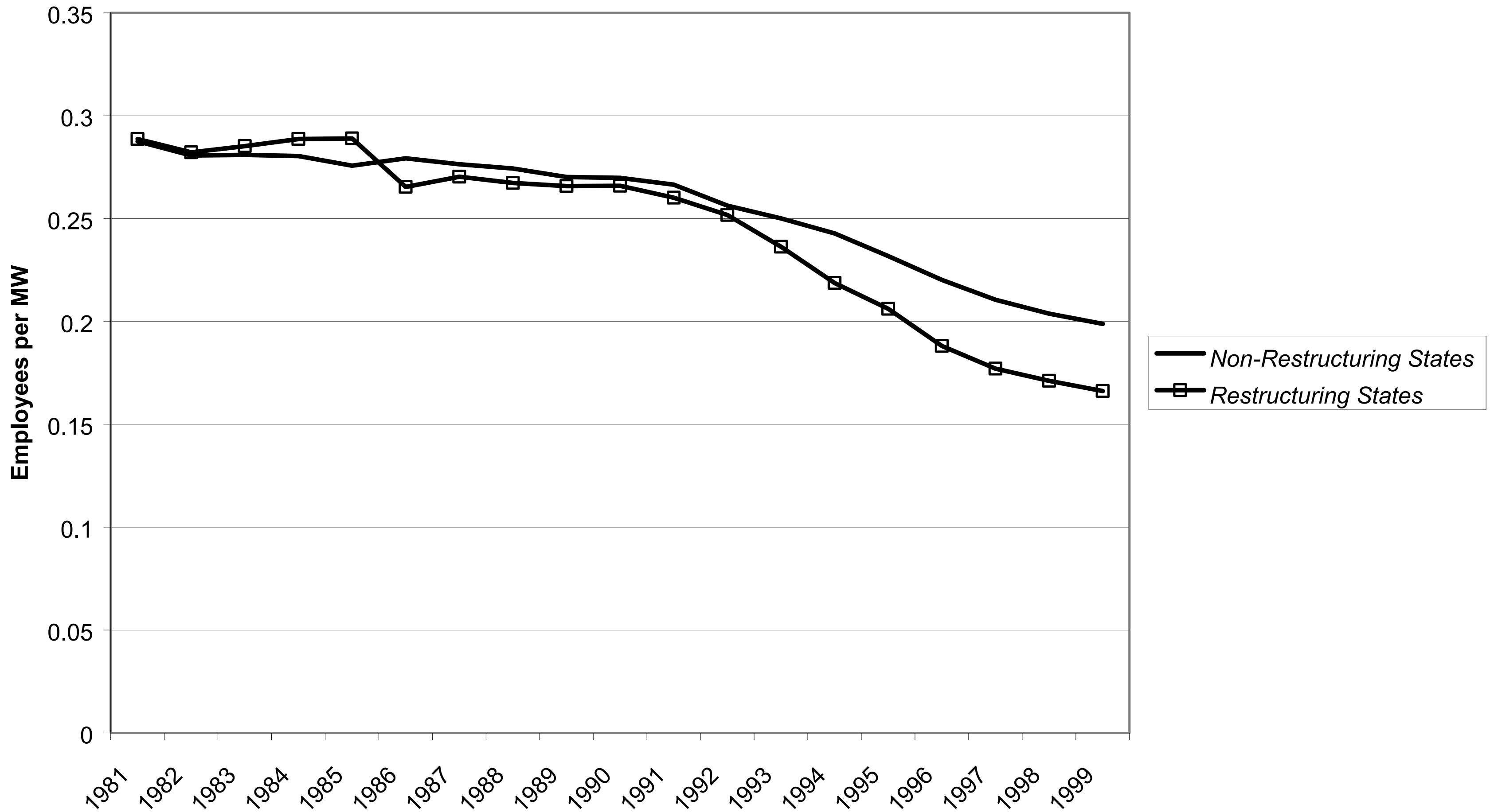

FIGURE 1: Average Employees per MW in Restructuring and Non-Restructuring States

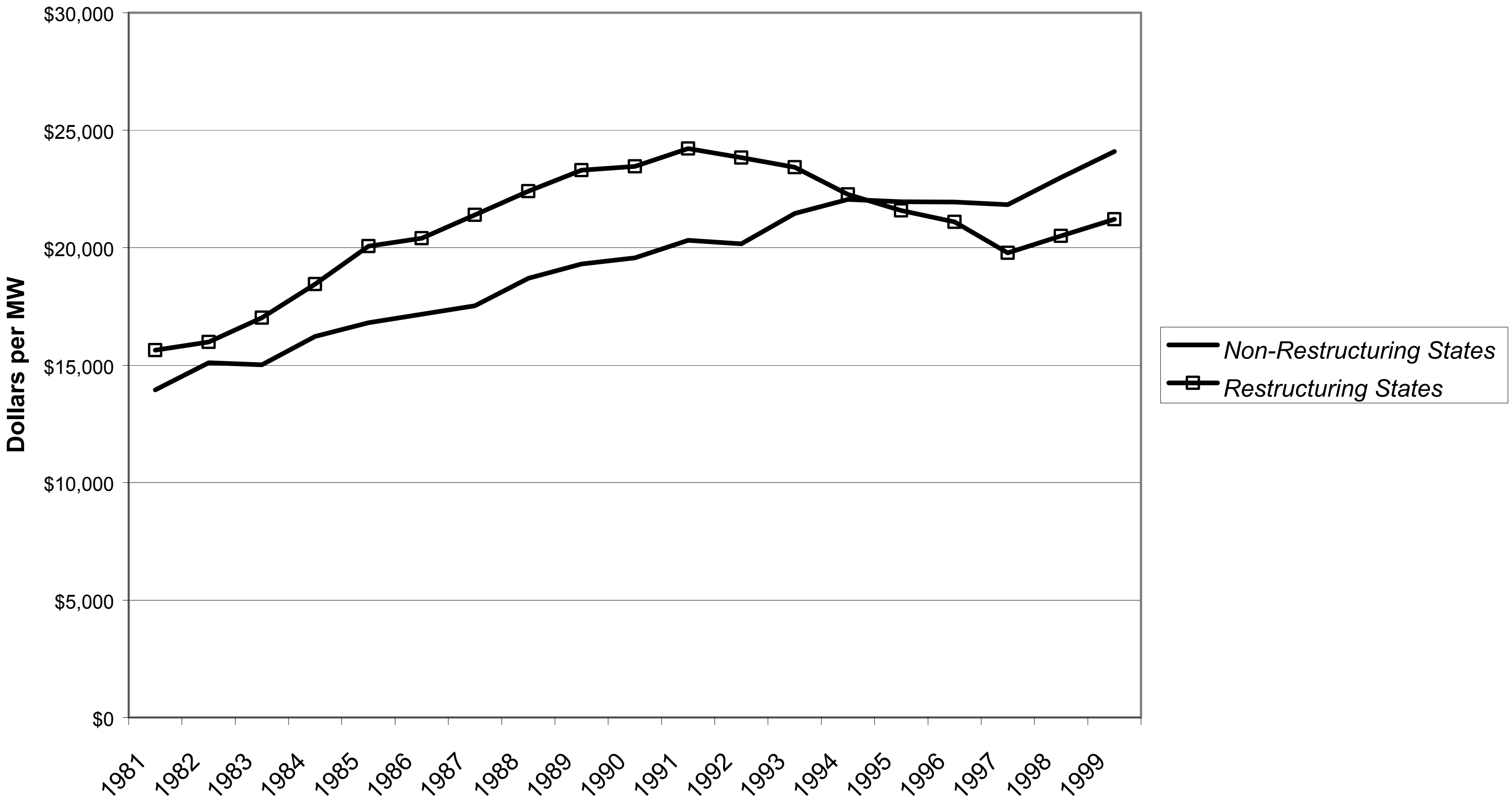

FIGURE 2: Average Non-Fuel Expenses per MW in Restructuring and Non-Restructuring States

FIGURE 3: Coal Expenses per MWH in Restructuring and Non-Restructuring States