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When Does Regulation Distort Costs? Lessons from Fuel Procurement in US Electricity Generation†

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This paper evaluates changes in fuel procurement practices by coal- and gas-fired power plants in the United States following state-level legislation that ended cost-of-service regulation of electricity generation. I find that deregulated plants substantially reduce the price paid for coal (but not gas) and tend to employ less capital-intensive sulfur abatement techniques relative to matched plants that were not subject to any regulatory change. Deregulation also led to a shift toward more productive coal mines. I show how these results lend support to theories of asymmetric information, capital bias, and regulatory capture as important sources of regulatory distortion. (*JEL* L51, L71, L94, L98, Q35, Q41, Q48)

Under what conditions does cost-of-service regulation lead to the distortion of production costs and methods? In this paper, I identify three leading potential mechanisms from the theoretical literature and measure their importance in contributing to distortions in fuel procurement and pollution abatement in US electricity generation. Under cost-of-service, regulators periodically audit utilities to determine a price of output that will allow "prudently incurred" variable costs to be recovered while delivering a rate of return that will attract private investment (Joskow 1974). The Averch-Johnson Effect (Averch and Johnson 1962) predicts that a rate of return that exceeds the cost of capital leads firms to adopt economically inefficient production techniques that are capital-biased. Second, when the regulator is unable to observe cost-reducing effort (and the cost of this effort), it becomes impossible to induce efficient cost-reducing activities (Laffont and Tirole 1986, 1993). Finally, input prices are predicted to differ from those prevailing under competition when special interest groups influence the regulator's decision on which costs to allow

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(Stigler 1971; Peltzman 1976; Grossman and Helpman 2002). I compare the importance of the mechanisms hypothesized by these theories at natural gas- and coal-fired electricity generating facilities following the end of cost-of-service regulation in states that passed electricity industry restructuring legislation.

By virtue of the need to transmit via public thoroughfares, the production and sale of electricity has historically been regulated by state or municipal governments in the United States (Stigler and Friedland 1962; Jarrell 1978). When not owned by the government, electricity providers have typically taken the form of vertically-integrated Investor-Owned Utilities (Utilities or IOUs). IOUs own the generating plants, the transmission network, and exclusive licenses to sell electricity in their respective service areas. In the mid- to late-1990s, state-level initiatives sought to restructure the electricity industry by transforming rate-regulated IOUs into participants in a competitive market guided by private investment, procurement, and production decisions. This required breaking up utilities so that owners of the transmission network could not favor their own plants in the face of lower-cost competition. This was often accomplished through divestiture, in which IOUs sold off their generating assets or transferred them to unregulated affiliates. Once divested, power plant operators' costs are no longer subject to oversight by the state Public Utility Commission. Although all states had at least held hearings to consider restructuring reforms by 2000, the California energy crisis put a halt to any legislation that had not already passed (Fabrizio, Rose, and Wolfram 2007). As a result, the regulation of electricity generators varies dramatically across states, with over half of states virtually untouched by any reform.

To measure changes induced by this deregulation, I construct a panel on the operations, fuel costs, and regulatory status of all gas- and coal-fired electricity generating facilities in the lower 48 states, responsible for roughly two-thirds of US electricity generation.[1] Although many plants initially ceased reporting costs following divestiture—as is standard when cost-of-service rules end—the Department of Energy's Energy Information Administration asserted its jurisdiction to collect data on fuel prices at deregulated plants beginning in 2002. This is the first study to evaluate the impact of deregulation on costs using detailed, restricted-access data from the post-divestiture period in US electricity generation.

I employ a matched differences-in-differences (DID) estimator in the spirit of Heckman et al. (1998) to compare fuel prices and sulfur regulation compliance strategies at similar divested and non-divested plants in close geographical proximity. The estimation strategy relies on the assumption that fuel purchasing opportunities are identical between "treatment" and "control" facilities after controlling for time-invariant differences. Close proximity is therefore a critical element of the estimation strategy because coal transportation costs are substantial and have changed over time. I find that divested plants reduce the price paid for coal by 12 percent relative to a counterfactual scenario in which their operations had continued under cost-of-service regulation.

A relatively small fraction of this gain may be attributed to the fact that divested generating units have been far more likely to have switched from bituminous to

[1] "Gas" and "Natural Gas" both refer to a gaseous mixture of hydrocarbons (mostly methane) extracted from underground deposits, and are used interchangeably.

cheaper, low-sulfur sub-bituminous coal.[2] The opposite is true of regulated generating units, which have disproportionately installed "scrubbers" as a means of compliance with sulfur emission regulations. Since scrubbers are enormously expensive pieces of equipment,[3] the fact that rate-regulated units would opt for more capital-intensive methods to achieve compliance with environmental regulations is consistent with the hypothesis of Averch and Johnson (1962).

The drop in the cost of coal following divestiture does not reflect the universal inefficiency of regulation. Instead, I find that divestiture had no impact on the price of fuel paid by gas-fired generators. These plants were owned by the same monopolistic IOUs operating coal-fired units, and were subject to the same change in regulatory oversight. Differences in the markets for natural gas and coal lend support to agency-based theories that emphasize the role of asymmetric information between firms and regulators as a source of distortion under regulation. While gas is a homogeneous commodity traded in regional markets with transparent prices, the market for coal is dominated by confidential bilateral contracts. In addition, shipping from mines is costly and plants must be specifically tuned to the heterogeneous characteristics of the coal being burned. Regulators therefore have less information on a coal-fired plant's purchasing opportunities, and operators may justify expenses based on idiosyncrasies of their location and equipment. It is clear, however, that these justifications become less important when generators become the residual claimants of cost savings through divestiture.

To evaluate the importance of regulatory capture on distorting procurement decisions, I confine my analysis to the set of plants that were burning coal sourced in-state during the pre-divestiture period. Coal producers are hypothesized to have greater influence over regulators in the states in which their mines (and jobs) are located. I find that divested facilities in these areas increase their out-of-state purchases by about 25 percent relative to matched non-divested facilities in coal-producing states, suggesting that regulation was an impediment to efficient procurement. I also find evidence suggesting that local coal has had some success in protecting their operations, as price reductions in these areas are mostly confined to plants that switched to burning low-sulfur coal.

I then connect my data on coal purchases to detailed data on mining cost determinants in the counties of origin. This allows me to decompose the extent to which these changes are driven by a reallocation of rents between mines and utilities, as opposed to real social welfare gains. I find that divested plants buy coal from mines with substantially lower extraction cost profiles: the mined coal seams are about 30 percent thicker and 50 percent closer to the surface than coal purchased by matched facilities. In total, divested plants purchase coal that requires $\sim$25 percent less labor to extract from the ground at mines that pay 5 percent higher wages.

Aside from any conclusions that may be drawn regarding the wider debates on the merits of government intervention in the economy, the sheer scale of the coal-fired

[2] Coal is classified by "rank," which refers to the purity of energy concentrated over millions of years of exposure to heat and pressure. In decreasing order of energy content, they are: Anthracite (mostly in Pennsylvania), Bituminous (Central Appalachia), Sub-bituminous (Wyoming, Colorado, Utah), and Lignite (Texas). About 90 percent of coal burned for electricity generation in the United States is Bituminous or Sub-bituminous.

[3] Capital costs vary by type of scrubber, but tend to be in the neighborhood of \$400/kW of capacity (EIA-923), compared to for a coal-fired plant in its entirety.

electricity sector makes these results of independent interest. Over 40 percent of electricity in the United States is derived from coal, and fuel accounts for about 80 percent of variable costs (Fabrizio, Rose, and Wolfram 2007). A 12 percent reduction in fuel prices at the coal-fired facilities that have already been divested amounts to about \$1B per year. These facilities account for roughly one quarter of US coal-fired generating capacity; the remaining facilities have not undergone any major changes in regulatory structure.

The structure of the paper is as follows: In Section I, I describe the process of divestiture in the United States and the institutional details that will facilitate estimation. Section II describes the theoretical bases for how cost of service regulation might distort costs, yielding a set of predictions to bring to the data. Section III details the estimation strategy, and Section IV describes the data that I will bring to bear on the question. Sections V and VI discuss the results and the associated welfare gains. Section VII concludes. There are two online Appendices: Details on the various data sources used in this study are contained in the online data Appendix. Additional results and robustness checks are detailed in online Appendix B.

I. Background on the US Electricity Industry

A. *Operations under Cost of Service Regulation*

The market for electricity was chaotic and competitive in its early years due to duplicative, non-exclusive franchises granted by municipalities (Jarrell 1978). At the turn of the twentieth century, improvements in economies of scale of generation and transmission led to widespread consolidation in the industry. State governments responded to this consolidation by asserting themselves over municipalities to regulate the operations of electricity companies in their respective states. Under the subsequent form of regulation, utilities have been granted exclusive licenses to sell electricity in their service territories in exchange for being subject to oversight of their operations and the rates they are permitted to charge customers. IOUs are guaranteed recovery of "prudent" costs incurred, as well as a predetermined rate of return on the value of the utility's capital base. All major investments can only be undertaken with the approval of the state's Public Utility Commission. The prices an IOU is permitted to charge are determined during "rate hearings." These costly, politically charged affairs entail an intensive audit of the utility's costs, operations, and demand projections in order to justify a change in the pricing formula for electricity.

Kahn (1971) argues that the regulatory lag between rate hearings leads many utilities to reduce costs between adjustments so as to reap profits during periods of fixed output price. After oil price spikes in the 1970s, many state commissions allowed IOUs to implement automatic pass-through clauses for fuel costs since intermittent rate cases could not keep up with the rise in the IOU outlays. Once the adjustment formula is set, IOUs are guaranteed recovery of their fuel costs without further oversight.

There are two additional types of facilities that deserve mention. An early effort to reduce the cost of electricity during the Carter Administration led to the Public Utility Regulatory Policy Act of 1978 (PURPA). PURPA made it (marginally) easier for non-utility generating facilities to sell power to regulated entities in an attempt to remove barriers to entry in the industry. This was followed by the Energy Policy

Act of 1992, which sought to remove some of the obstacles non-utilities faced when seeking transmission service from the IOUs who owned the wires. These reforms stimulated limited entry from non-utility generators, mostly co-generating facilities that also provided steam for industrial purposes (Joskow 2005).[4]

The final class of operators are federal, municipal, and cooperative organizations. These organizations produce about 20 percent of the nation's electricity (mostly in rural areas), and have made up about 20 percent of US coal-fired capacity since at least 1990. Public Utility Commissions do not have jurisdiction to regulate these entities since they are owned either by the government or their members. Facilities owned by either non-utilities or not-for-profits were not subject to divestiture and therefore do not experience operational or regulatory changes during the period of study.

B. *Restructuring and Divestiture*

In spite of the successful deregulation of US telecommunications (Olley and Pakes 1996); airlines (Kahn 1987 and Ng and Seabright 2001); railroads (McFarland 1989 and Ellig 2002); and trucking (Rose 1987), electricity was thought to be different. The fact that vertically integrated utilities owned both the generation assets and the wires meant that a deregulated firm would be able to shut out competition from other producers. Markets in electricity could also be vulnerable to the exercise of market power since electricity production must match demand in every moment in time—the impossibility of storage and high costs of plant construction raises the risk that a firm can unilaterally withhold capacity in the short-run to drive up prices with impunity.

Joskow and Schmalensee (1988) was groundbreaking in that their evaluation of the electricity industry confronted these challenges directly, and suggested a set of policy options that would facilitate the transition to a restructured market. Among these policies was that vertically-integrated IOUs divest their generation assets to prevent owners of transmission networks from favoring their own plants. Instead, generators would be required to bid their capacity in day-ahead and real-time auctions and would only be dispatched if their bid was below that of the marginal unit required to meet demand. This change transferred control of transmission networks to independent system operators in order to become participants in regional markets. Once divested, plant operators bear the full cost of their procurement decisions. Units that purchase relatively expensive fuel would be forced to raise their bids in wholesale markets and therefore become less likely to be called upon to operate.

Figure 1 shows the geographic distribution of these reforms with respect to coal-fired electricity stations in the United States that report fuel deliveries between 1990 and 2009.[5] Although divestiture policies precluded the possibility of IOUs cream-skimming from their best plants, it is clear that neither coal-fired plants nor restructuring reforms were randomly spread across the country. Almost all coal

[4] Less than 2 percent of coal-fired capacity belong to this class of power plants. The mid-2000s saw more substantial entry in the form of gas-fired non-utility generators.

[5] States that restructured, but do not have coal-fired generating assets reporting cost data include California, Maine, Rhode Island, and Washington, DC. New Hampshire introduced retail choice but did not require divestiture of generating assets. A more detailed discussion of the state-by-state history of divestitures can be found in online Appendix A.

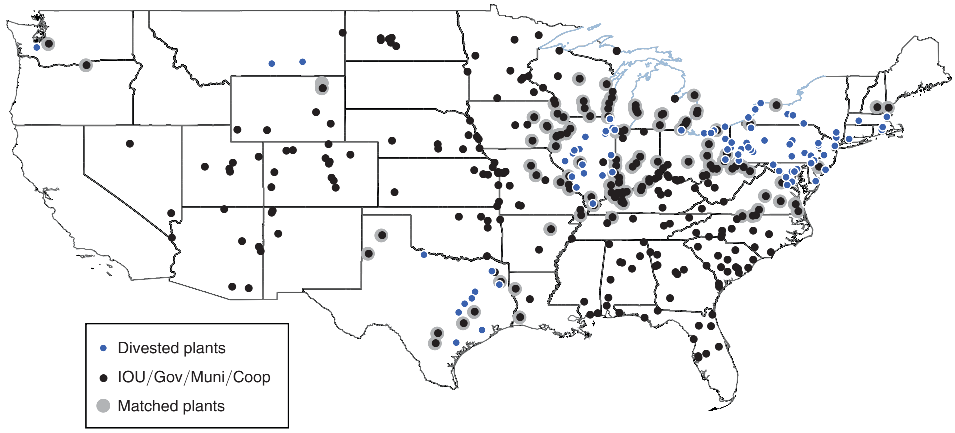

Figure 1. Coal-Fired Plants in the United States, 1990–2009

production and consumption occurs to the east of the Rocky Mountains. In spite of the high cost of shipping coal relative to transmitting the derived power by wire, the establishment of exclusive service areas by IOUs ensured local utilities would not be competed out of the market by producers near mines in the Ohio River Valley. This is one source of the price differential in electricity across areas that motivated restructuring legislation. Another major driver of restructuring legislation was the gap between retail and industrial electricity prices (White 1996). States with larger gaps were more likely to restructure due to the perception that retail consumers were getting a raw deal relative to industrial buyers.

Restructuring legislation was first passed in the Northeastern states and California in the mid-1990s. The movement had gained sufficient momentum by 1998 that every state in the union had at least held hearings on the prospective gains from deregulation (Fabrizio, Rose, and Wolfram 2007). This momentum dissipated quickly in the wake of the California electricity crisis of 2000–2001, leading several states who had made significant progress in the direction of restructuring to delay or cancel planned reforms (Joskow 2005). No state has passed restructuring legislation since this time: fairly or not, restructuring is popularly associated with the spectacular failure in California and a lack of significant offsetting benefits to consumers (Kwoka 2008).[6] As noted by Joskow (2006, p. 4), "Even the Cato Institute has lost patience with competitive reforms in electricity and appears to see merit in returning to the good old days of regulated vertically integrated utilities (Van Doren and Taylor 2004)."

That said, the states that had already restructured before the California crisis have not returned to the model of vertically-integrated IOUs. The perils of liberalized electricity markets have received significant scrutiny in the wake of the California electricity crisis (Borenstein, Bushnell, and Wolak 2002; Borenstein 2002; Bushnell, Mansur, and Savaria 2008; Mansur 2001, 2008), and adjustments have been made

[6]Borenstein, Bushnell, and Wolak (2002) find that the price of electricity would have tripled between 1998 and 2000 based on rising input costs alone. Although there were a number of factors that contributed to the crisis (including the exercise of market power), it was most certainly exacerbated by the fact that retail prices were fixed while wholesale prices were skyrocketing. This led generators to withhold capacity due to doubts of receiving compensation, not the exercise of market power. See Joskow (2001) for a detailed discussion of the history of the California electricity crisis.

to promote wholesale electricity markets that function reasonably well (Mansur and White 2012). Recent work has also shown that restructuring is associated with more productive nuclear generating facilities (Davis and Wolfram 2012) and declines in labor and non-fuel costs (Fabrizio, Rose, and Wolfram 2007).[7] The market for electricity in the United States is therefore characterized by a patchwork of regulatory structures that are separated by state borders and/or historical service area boundaries.

II. Sources of Regulatory Imperfection

To explore the possible mechanisms that can explain changes in firm behavior following deregulation, it is helpful to consider the main hypotheses posed in the theoretical literature on regulation-induced distortions. To do so, I consider a setting in which a firm can reduce the price paid for inputs by exerting cost-reducing effort. The fixed cost of this effort is compensated with a rate of return on capital that exceeds the cost, and the regulator may punish the firm for insufficient effort by refusing to reimburse costs deemed excessive. In a key departure from the agency literature, I leave the regulator's objective function unspecified. Rather than derive the optimal policy for the regulator, I am instead interested with how regulation affects the set of *feasible* policies. The reason for this approach is two-fold: it is sufficiently flexible to allow for consideration of different theories of regulatory inefficiency in a common framework, and it results in a set of hypotheses that can be taken to the data on firm behavior without having already assumed the nature of the regulator's objective function. Deriving comparative statics based on changes in the set of feasible policies is analogous to the analysis of demand functions conducted by Becker (1962)—applied here in a principal-agent framework.

Suppose generating facilities produce electricity by combining fuel (F) and capital (K) according to the quasi-concave production function $G(F, K)$; labor is a small share of generation costs and is ignored. Let p denote the per-unit compensation received by plant operators, whose determination will depend upon the regulatory environment. Given this price, plants face the inverse demand function $p = p[G(F, K)]$. For simplicity, assume a constant elasticity of demand, and denote its inverse $\eta = -\frac{G(F,K)}{p[G(F,K)]}\frac{dp}{dG}$, with $0 \leq \eta < 1$.[8] Plants exert managerial effort (e) to solicit bids, negotiate contracts, etc., and this effort reduces the price paid for coal according to $c = \beta - e$ where $e \in [0, \beta]$. Effort is itself costly and reduces profits according to a convex function $\psi(e)$, $\psi'(e) > 0$, $\psi''(e) > 0$.

Under "cost-plus" regulation, variable costs are reimbursed only if the regulator deems them "prudent" and the plant receives a rate of return s on its capital stock, or "rate base" that exceeds the cost of capital, r. The regulator is unable to directly observe cost-reducing effort and instead decides whether or not to allow fuel expenditures based only on the reported price. Let $\theta(\beta - e)$ denote the probability that

[7] Fabrizio, Rose, and Wolfram (2007) as well as concurrent work by Chan et al. (2012) define treatment as the time between law passage and divestiture because post-divestiture data on costs has not been utilized prior to this study.

[8] Sufficient conditions for a maximum will hold so long as the demand function is not so convex as to reverse the quasi-concavity of revenues with respect to inputs.

the regulator allows recovery of costs $\beta - e$. The firm therefore maximizes profits subject to the constraint that revenues are no greater than allowed costs:[9]

$$\max_{e,F,K} R(F,K) - (\beta - e)F - rK - \psi(e) \tag{1}$$

$$s.t. R(F,K) \leq \theta(\beta - e)[\beta - e]F + sK.$$

Letting λ denote the Lagrange multiplier on the revenue constraint, we have the first order conditions:[10]

$$[e] : \psi'(e) = F\{1 - \lambda[\theta(\beta - e) + [\beta - e]\theta'(\beta - e)\}$$

$$[F] : (1 - \eta)pG_F = \frac{[1 - \lambda\theta(\beta - e)]}{(1 - \lambda)}(\beta - e)$$

$$[K] : (1 - \eta)pG_K = r - \frac{\lambda}{(1 - \lambda)}[s - r].$$

The standard first order conditions for an unregulated firm follow from maximizing (1) without the revenue constraint: optimal effort equates marginal cost and benefit (a reduction in the cost of every unit of coal purchased). Since a monopolist will restrict output to raise price, the reduced demand for inputs implies less effort will be exerted to reduce input costs than in a competitive market.[11] Input costs in a deregulated market therefore depend on the ability of firms to exert market power.

Capital-bias is expressed clearly by assuming for a moment that the regulator approves all variables costs with certainty ($\theta(c) = 1 \forall c$). Instead of equating the relative marginal product of capital to the relative price, cost-plus recovery implies

$$\frac{G_K}{G_F} = \frac{r}{(\beta - e)}\left[1 - \frac{\lambda}{(1 - \lambda)}\frac{s - r}{r}\right] < \frac{r}{(\beta - e)}.$$

That the relative cost of inputs exceeds the technical rate of substitution under cost of service regulation is the basis of the famed "Averch-Johnson effect."[12] When cost recovery is guaranteed regardless of c, it is also clear that fuel prices are inefficiently high. This is because allowed revenues are directly tied to costs through the revenue constraint. While the plant bears the full cost of search effort, it only reaps

[9] To focus attention on cost reduction, it is assumed that the regulator is perfectly able to observe and dictate quantities conditional upon costs. This is equivalent to defining the analogous probabilities of approval for fuel and capital as unity at the quantities desired by the regulator, and zero otherwise.

[10] The binding revenue constraint and sufficient second order condition for a maximum imply $0 < \lambda < 1$: the determinant of the bordered Hessian of (1) is positive when $\lambda < 1$ and revenues are not too concave.

[11] Following Hicks (1935), the tendency for monopolists to have costs that exceed those prevailing under competition has been referred to as "the quiet life of the monopolist."

[12] See Baumol and Klevorick (1970) for a more complete treatment, and Berg and Tschirhart (1988, chapter 9) for a discussion of the subsequent literature on the Averch-Johnson effect.

benefits at rate $(1 - \lambda)$.[13] One strategy to mitigate these problems is to decouple revenues from costs via "yardstick competition" (Shleifer 1985). Under yardstick competition, the allowed output price is tied to the realized costs of *other* producers—thereby effectively setting λ and η to zero.

In the agency-theoretic approach, the regulator removes the unconditional guarantee of recovered costs in order to induce the plant to undertake the desired level of cost reducing effort and production. This is a relatively straightforward task when there is no uncertainty on intrinsic costs, β (i.e., the cost of fuel when no effort is exerted): the regulator approves the costs that maximize her objective function, and denies compensation otherwise. If we consider only differentiable strategies, first best outcomes are achieved when the regulator approves optimal effort e^* with certainty, and the probability of cost allowance at the optimum changes according to $\theta'(\beta - e^*) = -\frac{\theta(\beta - e^*)}{(\beta - e^*)}$. This neutralizes the effect of the rate of return constraint by increasing the probability of allowed costs one-for-one with cost-reducing effort—a zero net revenue effect. The plant's best response is to undertake efficient search effort so long as the resulting profits are non-negative.

In the presence of asymmetric information, the regulator must adopt a strategy of approving costs without observing effort or intrinsic costs. Suppose β can take on any value on the interval $[\underline{\beta}, \overline{\beta}]$ with some positive probability. Let $\underline{c} = \underline{\beta} - e^*(\underline{\beta})$ denote the costs realized when firms with intrinsic costs $\underline{\beta}$ exert the level of effort that would be optimal in a competitive, unregulated environment, $e^*(\underline{\beta})$, and similarly for $\overline{c}$. While it is possible for the regulator to induce efficient outcomes over some range of β, this becomes infeasible as the unobserved heterogeneity grows sufficiently large so that it is no longer possible to provide sufficient reward for lower costs.

To see this, first note that the efficient level of effort in the first-best world is decreasing in intrinsic costs, that is $\frac{de^*}{d\beta} < 0$. This is shown by differentiating the first order conditions of (1) with respect to β while noting input demand is a function of fuel price. The input demand conditions yield the standard $\frac{\partial F}{\partial c} = \frac{R_{KK}}{R_{KK}R_{FF} - R_{FK}^2} < 0$, by the assumed quasi-concavity of revenue. Differentiating the optimal effort condition yields

$$\frac{de^*}{d\beta} = \frac{\frac{\partial F}{\partial c}}{\frac{\partial F}{\partial c} + \psi''(e^*)}.$$

This implies optimal effort is decreasing in intrinsic costs so long as the convexity of the effort function is greater than the drop in fuel demand arising from higher fuel prices. This follows from the assumption that the revenue function is not too concave in order for the solution to (1) to be a maximum. As a result, optimal costs are increasing with intrinsic costs, $\frac{dc^*}{d\beta} > 0$. This makes sense, or otherwise we would have the perverse scenario in which firms with higher costs are producing more

[13] If we instead assumed that the regulator could fully compensate the firm for effort, effort would be efficient conditional upon quantities, but quantity would still be inefficiently low because the plant anticipates the effect of output on price.

than those with lower costs. Similarly, applying the envelope theorem to (1) when differentiating profits with respect to β implies that profits of an operating plant are strictly declining as intrinsic costs rise.

Suppose the regulator denies all costs greater than $\overline{c}$ certainty, and increases the probability of approval for lower costs according to $\theta'(c) = -\frac{\theta(c)}{c}$ for $c \leq \overline{c}$.[14] This is a feasible strategy to induce efficient search so long as $\theta(c) < 1$ and $\overline{\beta}$ is known by the regulator. However, as $\overline{\beta} - \underline{\beta}$ grows large, there will eventually be a region of β in which costs must be approved with certainty and lower cost firms are no longer rewarded for their efforts. Lower cost firms therefore collect an "information rent" through reduced effort. It is important to note that this is due to the *variance* of unobserved heterogeneity, not the *levels* of costs. When intrinsic costs are high, but observed, it is perfectly possible for the regulator to approve costs at the efficient level of effort. This is a classic result in principal-agent theory, typically proven in circumstances in which the regulator aims to maximize the sum of consumer surplus and profits. The point here is that efficient effort is impossible to induce under *any* regulator's objective function when unobserved heterogeneity is sufficiently large.

The inefficiency associated with regulatory capture is also straightforward to demonstrate. Suppose the local coal mines exert some influence over the regulator's decision making. In this case, the regulator approves fuel costs according to $\theta(c, b)$, where b represents the influence of the mines, perhaps via campaign contributions as in Grossman and Helpman (2002). In this case we can express the effect of this influence on allowed costs as $\frac{\partial\theta}{\partial b} > 0$; $\frac{\partial^2\theta}{\partial b \partial c} \geq 0$—contributions raise the probability of allowing high fuel costs, and reduce the punishment for marginally reducing effort.[15] To show how increased mining influence affects the cost-minimizing effort exerted by plants, suppose the regulator is initially inducing optimal effort with $\frac{\partial\theta}{\partial c} = -\frac{\theta(\beta - e^*, b)}{(\beta - e^*)}$ and consider the effect of a marginal rise in influence on search effort. Accounting for political influence via $\theta(c, b)$ in (1), differentiation of the analogous first order condition for effort with respect to b and substituting in for the initial policy yields

$$\frac{de^*}{db} = -\frac{F\lambda\left[\frac{\partial\theta}{\partial b} + (\beta - e^*)\frac{\partial^2\theta}{\partial c \partial b}\right]}{\psi''(e^*) + \frac{\partial F}{\partial c}}.$$

The denominator is positive by the same condition that implies $\frac{de^*}{d\beta} < 0$. Thus an increase in political influence leads to a decrease in cost-reducing effort, and higher fuel prices.

We have therefore derived a core set of predictions to test against the data. The price of fuel is expected to remain constant after divestiture when determinants of cost are readily observable by a regulator who is operating relatively freely of political constraints imposed by fuel suppliers, and the firm is unable to exert market power. Conversely, both opacity in the procurement process and political influence

[14] $\theta(\overline{c})$ itself can take on any value less than unity so long as the premium on capital is sufficiently high to preserve solvency.

[15] In fact, the necessary assumption is that $\frac{\partial^2\theta}{\partial b \partial c}$ not be so negative as to reverse the direct effect of $\frac{\partial\theta}{\partial b}$.

tend to raise input prices above levels observed by plants operating in a competitive market. Working against these forces is the potential that prices might rise if market power considerations lead firms to substantially reduce output. Finally, divested plants are anticipated to favor less capital-intensive production methods than when they are compensated based on the value of their capital stock.

III. Estimation Strategy

To estimate the impact of plant divestiture on coal procurement practices, I compare changes at facilities in close proximity that burned the same rank of coal in 1997, before divestitures began.[16] This strategy is similar to the conditional DID estimator of Heckman et al. (1998), but matches on geographic proximity and binary baseline characteristics (rank of coal burned), rather than the propensity score.[17] This approach is designed to account for unobserved or endogenous time-varying determinants of the outcome variable that differ between treatment (divestiture) and control groups. In the case of coal procurement, these confounders are due to the combination of substantial shipping costs and wide geographic dispersion of plants between treatment and control groups.[18]

More formally, suppose we have N plants indexed $i \in \{1, \ldots, N\}$ so that plants $i \in \{1, \ldots, N_0\}$, $N_0 < N$ are never divested, but those with $i \in \{N_0 + 1, \ldots, N\}$ eventually are. There are T time periods indexed $t \in \{1, \ldots, T\}$, and T_0 pretreatment time periods with $1 < T_0 < T$. Using the "Potential Outcomes" framework popularized by Rubin (1974), let $Y_{it}(0)$ denote the price of coal per one million British Thermal Units (MMBTU) paid by a non-divested facility i in period t. Similarly, let $Y_{it}(1)$ denote a facility that has been divested. Suppose fuel costs at non-divested facilities are

$$Y_{it}(0) = \gamma_i + \delta_t + c_t(X_i, 0) + \nu_{it},$$

where $c_t(X_i, 0)$ represents a time-varying procurement cost function that depends on facility i's location X_i (a richer set of pretreatment covariates is possible), and regulatory status. Suppose that divestiture induces procurement cost $c_t(X_i, 1)$, but that time invariant costs γ_i are unaffected by regulatory status (an example would be "last mile" costs that are idiosyncratic to the plant). Then coal prices at divested facilities can be written as

$$\begin{aligned} Y_{it}(1) &= Y_{it}(0) + [c_t(X_i, 1) - c_t(X_i, 0)] \\ &= Y_{it}(0) + \tau_t(X_i), \end{aligned}$$

[16] The variance in heat, sulfur, and ash content across rank is much greater than within rank, so switching across ranks requires more costly adjustments than the tuning needed to switch suppliers within rank. The procurement options available to two plants in close proximity are likely to overlap when they burn the same rank of coal.

[17] I do not use propensity scores because a spatial mapping of scores—even based on coordinates alone—produces an essentially nonsensical function for even high-order polynomials. It is simply not possible to produce a meaningful propensity score function that fits the map of divested facilities observed in the data.

[18] The assumption of time-invariant differences between treatment and control groups has been more common in the divestiture literature when studying plant efficiency. See, for example, Bushnell and Wolfram (2005); Davis and Wolfram (2012); and Chan et al. (2012).

where $\tau_t(X_i)$ represents the relative procurement cost between being divested and regulated at location X_i in period t. The observed fuel price at plant i in period t is therefore

$$Y_{it} = Y_{it}(0) + \tau_t(X_i)D_{it},$$

where

$$D_{it} = \begin{cases} 1 & \text{if } i > N_0 \text{ and } t > T_0 \\ 0 & \text{otherwise.} \end{cases}$$

The difficulty in estimation is that only control facilities in close proximity to X_i are suitable to serve as counterfactuals for the price $Y_{it}(0)$, and only after permanent facility-specific differences and common transitory shocks have been taken into account.

As in the matching literature (Dehejia and Wahba 1999; Heckman, Ichimura, and Todd 1997), let $1\{\,\}$ denote an indicator function that evaluates to one if the statement in braces is true, and let $D_i \equiv \max\{D_{it}\}$ denote treatment group, and $l_m(i)$ be the index of facilities with $D_l \neq D_i$ and

$$\sum_{j|D_j \neq D_i} 1\{||X_j - X_i|| \leqslant ||X_l - X_i||\} = m. \tag{2}$$

Equation (2) identifies the m closest facilities of the opposite treatment group according to the norm metric $||\cdot||$. I match exactly on the most common rank of coal (bituminous, sub-bituminous, or other) burned at baseline, then based on geographic proximity. An alternative approach is to match all facilities j with a caliper on distance, $||X_j - X_i|| < d$, rather than based on a fixed number of matches. Results will be shown to be robust to the choice of matching metric. With a (possibly unbalanced) panel, it is possible to estimate $\tau_t(X_i)$ with a DID estimator applied to facilities i and the m facilities whose distance from X_i satisfies (2):

$$Y_{it} = \gamma_i + \delta_t + \tau_t(X_i)D_{it} + \varepsilon_{it}.$$

The average treatment effect on the treated, $\tau = E[\tau_t(X_i)|D = 1]$ can be estimated by taking the average over the divested facilities of the derived $\hat{\tau}_t(X_i)$, or more efficiently,[19] by pooling the data of the divested facilities and their nearest neighbors in a single fixed-effects DID estimation that weighs each matched control facility by the inverse of the number of matches to facility i in period t, then clusters standard errors at the facility level. That is, if control plant 1 is one of five plants matched to treatment plant A and one of ten plants matched to treatment plant B, it receives

[19] Technically one would want to include separate time effects for each X_i. This increases the number of parameters by $T^{(N-N_0)}$ to reduce a component of the error term that is orthogonal to the treatment parameter due to the balance between treatment and matched control units. Severe collinearity of proximate time effects also introduces nonsingularity to the variance matrix when jointly estimated. For these reasons, all estimates are based on a common set of time dummies.

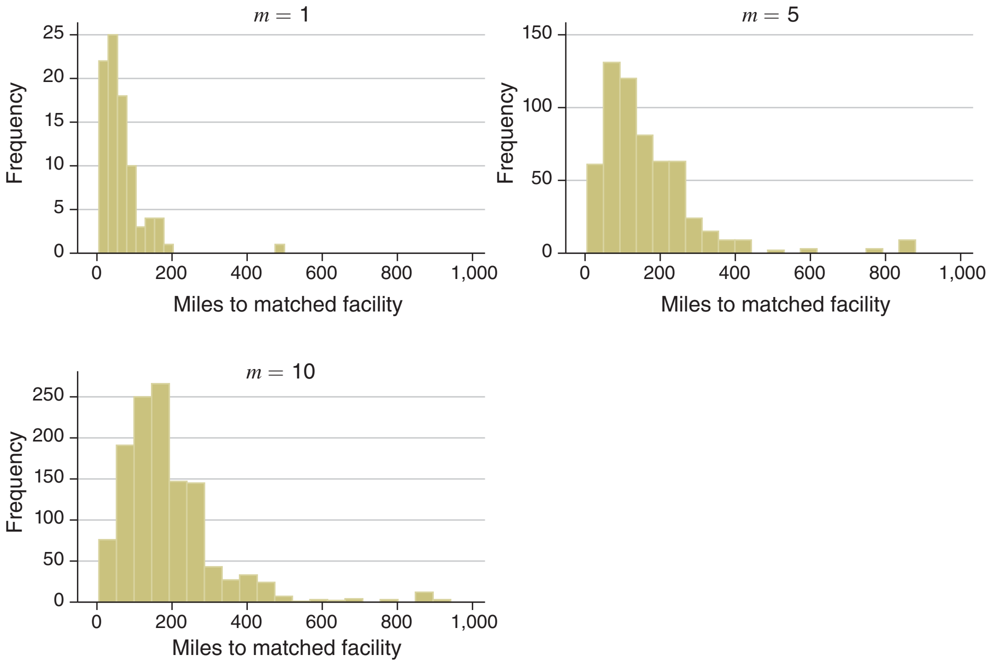

Figure 2. Distance Between Divested and Matched Facilities

weight 0.3, while all treatment plants receive weight 1. Weights sum to $2(N - N_0)$, and all unmatched control plants receive weight 0.[20]

Figure 2 shows the distribution of distance between divested and matched facilities under three potential thresholds. All results based on matching the m closest non-divested facilities constrain the search radius to 200 miles—beyond this point the quality of the counterfactual diminishes without much gain in terms of broadening the samples (all facilities but one have at least a single match within 200 miles). Estimates based on various search radii show that the results are not particularly sensitive to this choice of cutoff. Constraining the sample to these matches yields the set of non-divested facilities shown with gray markers in Figure 1. It is clear that this estimation strategy is not well suited to estimating an average treatment effect for all US plants, as the facilities in the Southeast, Upper Midwest, and Southwest are all hundreds of miles from the nearest divested facility. It is therefore not possible to estimate a credible counterfactual of how these non-divested plants would have operated if they had been subject to divestiture with this econometric framework.

This estimation strategy compares plants just across state lines, or within the same state, but exempted from restructuring due to public/cooperative ownership. This introduces the potential for confounding if restructuring were adopted as part of a broader deregulatory movement that might affect fuel prices in these states. To account for this possibility, Table B.5 of the online Appendix reproduces the core

[20] This is similar in flavor to the synthetic control group approach of Abadie and Gardeazabal (2003) and Abadie, Diamond, and Hainmueller (2010), who match on pretreatment outcome variables. Here I give priority to geography to avoid matching plants with similar baseline prices, but quite different choice sets due to location.

results while including quadratic, state-specific trends without a statistically significant impact on the coefficients.

A second concern regards the inclusion of Government/Municipal/Co-op-owned plants as potential controls. Although Gov/Muni/Coop plants do not face any changes in regulatory oversight during this period of time, it is not obvious that the incentives facing operators of these plants would parallel those of IOUs—a necessary condition to use these facilities to form a counterfactual for divested plants. This is a testable assumption and Figure B.1 of the online Appendix does so using the matching methodology developed in this section with $m = 10$. The difference between the two groups is statistically significant for one month over 20 years, and they follow nearly identical paths aside from a brief convergence in 2002. This suggests that Gov/Muni/Coop plants nearby divested facilities perform equally well as IOU facilities to estimate the counterfactual prices that would have prevailed in the absence of divestiture. The online Appendix provides an additional check by running the main specifications without these plants. As with state-specific trends, the coefficients are a percent or two lower but not statistically different than those presented below.

A final caveat that must be mentioned in the discussion of this methodology is the potential for bias due to violation of the stable unit treatment value assumption (SUTVA). The plants that serve to form counterfactual estimates are participants in common markets (for coal and emissions, for example) with treated plants. It is therefore critical to interpret the estimated coefficients with an eye toward how the behavior of divested plants may have affected the decisions made by the control units.

IV. Data

This study utilizes a detailed and comprehensive panel dataset I have constructed from a combination of publicly-available and restricted-access data on the operations of the US electricity sector from 1990–2009. Data on fuel expenditures, generating unit configurations, plant operations, and regulatory status are from the Department of Energy's Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). Data on the mines from which coal is sourced are from the Mine Safety and Health Administration (MSHA), the US Geological Survey (USGS), and the Bureau of Labor Statistics (BLS). The online data Appendix describes each of the constituent elements in greater detail. Instead, this section focuses on describing the data in the context of potential threats to the validity of the proposed estimation strategy.

A. *Plant-Level Characteristics*

Panel A of Table 1 presents summary statistics at baseline (1997) of plant characteristics by treatment group. While divested plants are a few years older, the only substantial difference between the two groups is the likelihood of being subject to an "incentive regulation" program, a common precursor to restructuring. The matched sample weights the data from non-divested plants in proportion to the number of divested plants matched for $m = 10$, subject to the constraint that plants be within 200 miles. Matching removes two-thirds of the non-divested plants from the sample, but only one divested facility is without any matches meeting this criteria. The high

Table 1—Summary Statistics at Divested and Non-Divested Plants in 1997

	Full sample			Matched only		
	Divested	Not divested	Difference of means	Divested	Not divested	Difference of means
Panel A. Plant characteristics						
Capacity (MW)	799.79	797.48	2.32	803.95	648.72	155.23
	[671.86]	[730.74]	(82.63)	[674.61]	[657.66]	(119.86)
Annual capacity factor	0.59	0.57	0.02	0.59	0.55	0.04
	[0.19]	[0.18]	(0.02)	[0.19]	[0.22]	(0.05)
Plant vintage	1961.99	1964.72	−2.73*	1962.14	1962.91	−0.78
	[10.92]	[13.53]	(1.39)	[10.90]	[14.04]	(2.20)
Percent scrubbers installed	0.25	0.32	−0.07	0.25	0.26	−0.01
	[0.44]	[0.47]	(0.05)	[0.44]	[0.44]	(0.08)
Incentive regulation utilities	0.44	0.15	0.29***	0.45	0.07	0.38***
	[0.50]	[0.36]	(0.06)	[0.50]	[0.25]	(0.06)
Facilities	88	309	397	87	101	188

	Full sample			Matched only		
	Divested	Not divested	Difference of means	Divested	Not divested	Difference of means
Panel B. Coal deliveries						
Millions MMBTU delivered	44.76	44.18	0.58	44.93	37.36	7.57
	[42.78]	[43.01]	(5.16)	[43.00]	[37.48]	(7.19)
Price($/MMBTU)	1.42	1.20	0.21***	1.42	1.30	0.12
	[0.37]	[0.37]	(0.04)	[0.37]	[0.34]	(0.08)
Percent spot market	0.24	0.27	−0.03	0.23	0.27	−0.04
	[0.29]	[0.32]	(0.04)	[0.28]	[0.36]	(0.06)
Years to contract expiry	5.37	7.95	−2.58***	5.42	7.42	−2.00
	[6.19]	[7.21]	(0.88)	[6.23]	[7.92]	(1.28)
Percent sourced in-state	0.41	0.30	0.12**	0.41	0.40	0.01
	[0.46]	[0.44]	(0.05)	[0.46]	[0.45]	(0.08)
Percent bituminous	0.76	0.62	0.13**	0.76	0.76	−0.00
	[0.42]	[0.46]	(0.05)	[0.42]	[0.42]	(0.07)
Sulfur content (lbs/MMBTU)	1.19	1.02	0.17*	1.19	1.34	−0.16
	[0.72]	[0.81]	(0.09)	[0.73]	[0.87]	(0.14)
Ash content (lbs/MMBTU)	8.67	8.03	0.64	8.56	9.45	−0.89
	[4.83]	[4.15]	(0.56)	[4.75]	[7.74]	(1.38)
Mine distance (mi.)	318.10	364.92	−46.82	321.01	264.58	56.43
	[330.64]	[312.52]	(39.38)	[331.42]	[299.16]	(47.52)

	Full sample			Matched only		
	Divested	Not divested	Difference of means	Divested	Not divested	Difference of means
Panel C. Generating units						
Boiler vintage	1962.97	1965.25	−2.28***	1962.41	1963.95	−1.54
	[10.65]	[12.43]	(0.84)	[10.24]	[11.88]	(1.35)
Connected nameplate (MW)	328.53	290.81	37.73*	325.91	281.13	44.78
	[265.07]	[268.24]	(20.27)	[268.49]	[275.55]	(33.25)
Capacity factor	0.77	0.79	−0.02	0.77	0.76	0.01
	[0.22]	[0.19]	(0.02)	[0.22]	[0.25]	(0.04)
Bituminous	0.80	0.79	0.01	0.84	0.84	−0.00
	[0.40]	[0.41]	(0.03)	[0.37]	[0.37]	(0.04)
Potential sulfur emissions (1,000 tons/year)	11.43	8.61	2.82***	11.35	11.54	−0.19
	[14.26]	[13.55]	(1.08)	[14.69]	[18.30]	(1.98)
Percent scrubbers	0.16	0.20	−0.04	0.13	0.13	0.00
	[0.37]	[0.40]	(0.03)	[0.34]	[0.34]	(0.04)
Facilities	88	310	398	79	76	155
Generating units	215	849	1,064	197	197	394

Notes: Data from non-divested facilities in the matched samples receive weight $1/m_j$ for each matched divested facility j. Matching criterion: $m = 10$ burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Standard errors clustered by facility in parentheses for panels A and B, by unit for panel C, and standard deviations in brackets.

***Significant at the 1 percent level. **Significant at the 5 percent level. *Significant at the 10 percent level.

degree of balance between the two groups is consistent with the history of power plant construction. Generating capacity is closely related to economic activity, which is spatially correlated. It therefore makes sense that areas that grew together in the middle of the twentieth century made similar decisions to expand their generation capacity. Again, the exception is exposure to incentive regulation, which is consistent with the relationship with eventual restructuring. The fact that divested plants were disproportionately already attempting to reduce costs suggests findings may be somewhat biased against subsequent cost reductions.

It is important to note that entry and attrition of coal-fired plants were rare during the sample period, and are unlikely to be sources of bias. Stringent environmental regulations on new boilers combined with high capital costs have made new coal plant construction largely uneconomical. In total, 96 percent of coal heat in 2009 was delivered to plants reporting in 1990 (slightly more after accounting for the non-reporting of permanent non-utilities prior to 2002). As a fraction of plants, 92 percent of plants reporting in 2009 also reported in 1990. For attrition, the combination of high entry costs with the high value from operating during periods of peak demand justifies maintenance costs at most aging facilities. Ninety-four percent of plants operating in 1990 continued to report fuel deliveries in 2009. The plants that closed tended to be small and rarely used—as a group they accounted for less than 2 percent of the heat delivered in 1990.

B. *Data on the Cost and Quality of Coal*

This study uses detailed data on coal deliveries to power plants from the EIA (details can be found in the online data Appendix). This is monthly shipment-level data, reported for nearly all of the coal burned for the production of electricity in the United States (all facilities with a combined capacity greater than 50MW are required to report). Although data on prices are redacted from public release for non-utilities, restricted-access data on prices were made available for this study under a non-disclosure agreement with EIA.

One critical caveat is that plants were no longer required to report to FERC upon divestiture, and EIA did not assert their authority under the Federal Energy Administration Act of 1974 to resume collection from non-utility plants until 2002. Plants that were sold before 2002 therefore have a gap in reporting following divestiture. With most divestitures occurring between 1999 and 2001, this results in a two year gap on average.

Figure 3 shows how the delivered and mine-mouth nominal prices for bituminous and sub-bituminous coal have evolved over time. This figure again emphasizes the importance of shipping costs, as the price of bituminous coal is nearly 50 percent higher upon delivery than at the mine and sub-bituminous prices more than double. This figure also shows a reason for the increasing popularity of sub-bituminous coal, as the average delivered price has fallen below the mine-mouth price for bituminous. While the delivered price depends on the spatial distribution of selected plants, the crossing in the early 2000s means that for plants that switched, sub-bituminous was cheaper on average than bituminous coal, even for plants located at a bituminous mine-mouth. After flat or declining prices through much of the 1990s, the delivered price of coal has roughly doubled for bituminous and increased by about

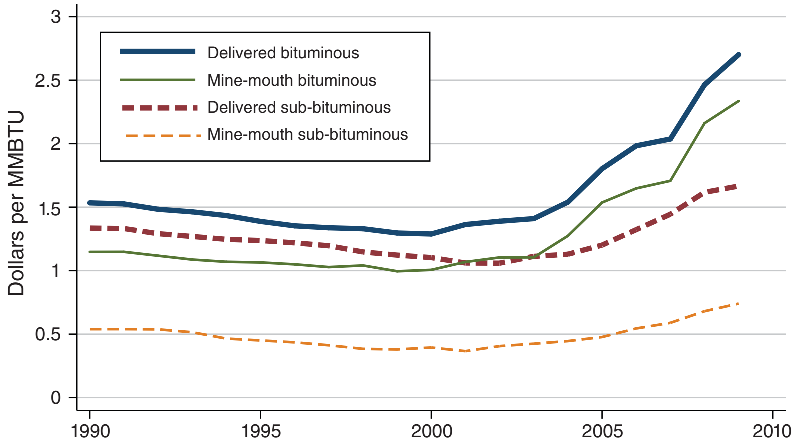

Figure 3. Coal Prices per MMBTU by Rank, 1990–2009

Note: Mine-mouth prices from EIA Annual Energy Review Table 7.9 (2011) and converted to heat units using average heat content by year and rank as reported in Forms EIA-423,923 and FERC 423.

50 percent for sub-bituminous coal over the last decade. Increases in mine-mouth prices only account for about half of the rise in sub-bituminous prices, the rest is due to increased shipping costs (both in terms of shipping rates and expanded delivery areas). Increases in bituminous prices since 2003 are largely due to increased mining costs and international demand.[21] All told, expenditures on coal for generating electricity averaged about \$23B through most of the 1990s and have increased rapidly since 2002 to about \$40B in 2009 (see online Appendix Figure A.1b). Expenditures among divested facilities since reporting commenced in 2002 are about \$8B per year on average.

Panel B of Table 1 presents summary statistics on the characteristics of coal deliveries reported to FERC/EIA in 1997 (the final pre-divestiture year for all plants). As detailed in Joskow (1985, 1987, 1988), the market for coal is largely conducted through long-term bilateral contracts, with supplemental demand procured on the "spot market," which are themselves short-term bilateral contracts in practice.[22]

At baseline there are substantial differences in the characteristics of coal delivered to divested and non-divested plants, though the volume of heat procured is similar. Many of the differences in the characteristics of coal purchases between divested and non-divested facilities are due to geographical dispersion and are eliminated through matching. In fact, there are no statistically significant differences between coal delivered to divested plants and their matched counterparts.

Since the estimation strategy relies on comparing changes over time, it is also important to ensure that preexisting trends are not responsible for the subsequent differences between treatment and control units. Figure 4 examines the common

[21] Crippling weather events in Chinese and Australian coal fields in 2007 led to a spike in demand for US bituminous coal, causing the price to rise nearly 50 percent (intra-year spikes were even higher).

[22] These contracts typically take the form of "base plus escalation:" initial prices are set to reflect current market conditions and the price subsequently rises or falls based on a producer price index for coal production.

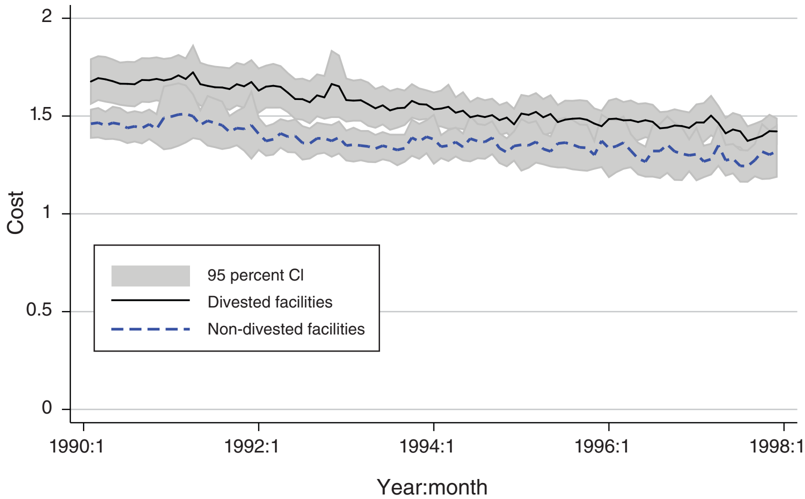

Figure 4. Pre-Trend Test: Matching Estimates of Delivered Coal Price, 1990–1997

Notes: Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility.

pretreatment period between divested plants and their matched counterparts with $m = 10$. It provides encouraging evidence that both treatment and control groups were following parallel paths throughout the 1990s.[23] It appears that the 12 cent premium paid in 1997 by IOU facilities that would later be divested was a relatively constant feature of coal deliveries. It would be difficult to attribute the decline in prices paid by divested facilities in subsequent periods to mean-reversion, as there is no evidence that prices were moving in different directions before divestiture.

C. *Unit-Level Characteristics*

Although coal deliveries are reported at the facility level, the decision to switch the rank of coal burned or install a scrubber is unit-specific (a coal-fired "unit" typically consists of a boiler connected to a generator, steam cooling, and pollution abatement equipment). On average, there are two to three coal-fired units operating per facility.

Panel C of Table 1 presents summary statistics on coal-fired unit characteristics, both nation-wide and in the matched sample. The number of facilities here and those in the plant-level analysis are slightly different due to reporting requirements at the unit-level. In addition, the matching criteria at the unit-level also includes the presence of a scrubber. This is important when estimating the differential probability of adding a scrubber after divestiture. This additional matching requirement eliminates a handful of divested facilities, and about 25 percent of non-divested facilities. As with the plant-level data, matching removes any statistically-significant differences between divested and non-divested units.

[23] If one squints, there might be a slight narrowing of the gap around 1993, perhaps due to the introduction of incentive regulation programs.

TABLE 2—COAL: MATCHED DID ESTIMATES OF LOG(*Price*) AND DIVESTITURE

	(1)	(2)	(3)	(4)	(5)	(6)
Post-divest	−0.124***	−0.188***	−0.152*	−0.124***	−0.128***	−0.136**
	(0.044)	(0.058)	(0.077)	(0.045)	(0.046)	(0.064)
m nearest neighbors				10	5	1
Proximity threshold (mi.)	200	100	50			
Year-month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.721	0.712	0.668	0.723	0.726	0.738
Facilities	230	146	69	198	166	121
Divested facilities	87	74	39	87	87	87
Observations	47,024	28,449	12,682	37,495	32,958	23,336

Notes: Dependent variable is log(*Price*) of Coal per MMBTU, including shipping costs. Non-divested facilities receive weight $\frac{1}{m_{-j}}$ for each matched divested facility j burning the same rank of coal in 1997, subject to the indicated matching criterion. Standard errors clustered by facility in parentheses.

*** Significant at the 1 percent level.
** Significant at the 5 percent level.
* Significant at the 10 percent level.

V. Results

This section evaluates the conditions under which divestiture led to a change in behavior by power plant operators, and relates these results to the hypotheses posed by theories of regulatory inefficiency. I begin with coal prices, and show the robustness of the estimation strategy to various assumptions and specifications. I then contrast the results for coal with those of natural gas as evidence of the importance of asymmetric information in distorting procurement decisions under regulation. I then look at sulfur regulation compliance decisions in the context of capital-bias hypotheses, and show that the disproportionate switch to low-sulfur coal among divested plants does not explain much of the observed drop in relative price. Finally, I constrain my analysis to plants that were initially burning in-state coal and relate their change in procurement behavior to theories of regulatory capture by politically-active coal mines.

A. *Deregulation and the Price of Coal*

Table 2 shows the change in log-price associated with plant divestiture using the matched DID estimator. To evaluate the robustness of the estimates to matching criteria, the first three columns use a caliper on distance, while the last three vary the number of matches. One shortcoming of the distance caliper approach is that the number of divested facilities with *any* matches within the specified distance drops off as the criteria becomes more stringent, which changes the composition of divested plants. This caveat aside, all matching specifications show large and statistically significant drops in the relative price paid for coal following divestiture. The results using a fixed number of matches rather than a distance threshold are stable and significant regardless of the number of matches included. Taken together, these estimates show a 12–13 percent drop in the price that divested facilities have paid for coal relative to nearby generation stations that were similar both on the characteristics

Table 3—Coal: DID Estimates of log(*Price*) and Divestiture

	(1)	(2)	(3)	(4)	(5)	(6)
Post-divest	−0.051	−0.054	−0.131***	−0.055	−0.069*	−0.137**
	(0.035)	(0.035)	(0.041)	(0.036)	(0.040)	(0.055)
Divest	0.145***					
Facilities	(0.030)					
Proximity threshold (mi)				200	100	50
Year-month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE		Yes	Yes	Yes	Yes	Yes
Division-year FE			Yes			
R^2	0.252	0.772	0.803	0.733	0.700	0.712
Facilities	397	397	397 333	221	123	
Divested facilities	88	88	88	88	78	47
Observations	86,225	86,225	86,225	71,569	47,324	26,483

Notes: Dependent variable is log(*Price*) of Coal per MMBTU, including shipping costs. Columns 1–3 include all facilities. Columns 4–6 include divested facilities that have non-divested matches within the specified distance with their unweighted controls. Standard errors clustered by facility in parentheses.

*** Significant at the 1 percent level.
** Significant at the 5 percent level.
* Significant at the 10 percent level.

of the facility, coal, and trends before divestiture occurred. When using levels rather than logs, this is about 25 cents per MMBTU of coal heat delivered. Based on the post-divestiture period average annual coal expenditure at divested facilities (about \$8B per year), the treatment on the treated estimate amounts to \$1B fewer dollars per year being spent on coal, holding quantities constant.

One can see the effect that the weighting procedure employed by the matched DID estimator has by comparing the results from Table 2 with those of Table 3, which uses a standard difference-in-difference estimator. The first three columns include the full sample of coal plants in the United States. The first two specifications rely on the assumption that divested and non-divested facilities would have followed parallel paths in the absence of restructuring—there are no time-varying differences between the two groups. Under this assumption, divestiture is associated with a modest, but statistically insignificant drop in purchased coal price. The third specification relaxes the common-trend assumption by allowing the price of coal to vary by census division-year. As a result, the post-divestiture coefficient measures the percent change in coal prices at divested facilities compared to non-divested facilities within the same census division, which has a similar flavor to the approach proposed in Section III. The drop in prices paid by divested coal plants is quite close to those of Table 2 using this specification.

The final three columns of Table 3 are also based on a standard difference-in-difference estimator, but they limit the sample based on proximity to divested plants. These are unweighted analogs to columns 1–3 of Table 2, in which the baseline rank of coal is not considered. These specifications show that while estimates of the effect on coal prices remain negative, the magnitude is sensitive to the threshold distance for inclusion in the sample. At 100 miles, the coefficient is 7 percent and is only marginally statistically significant. However, the loss in precision from limiting the sample to closer facilities is more than offset by the substantial increase in the coefficient estimates for the other specifications. The weighting procedure used in Table 2 puts greater

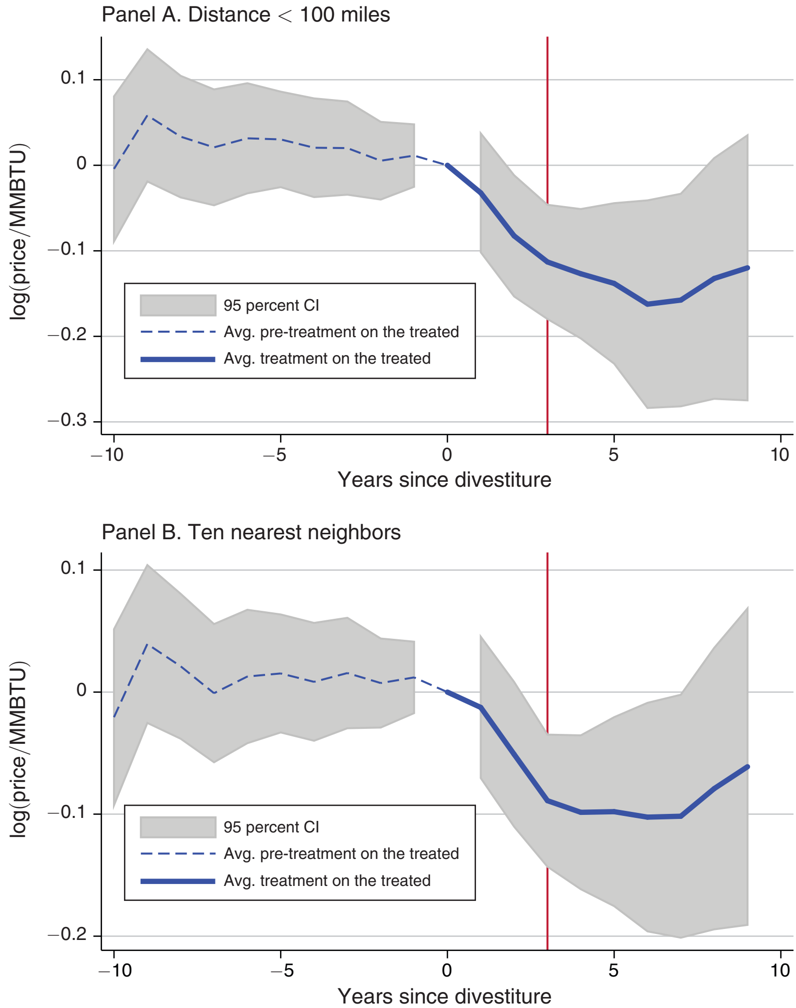

Figure 5. Matching by Year from Divestiture: log($Price$)

Notes: Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. m_j denotes the number of divested facilities burning the same rank of coal in 1997, and is located within 100 miles of the divested plant. Confidence intervals based on standard errors clustered by facility. The vertical line denotes the third year post-divestiture, the point at which most divested facilities resumed reporting fuel costs.

emphasis on non-divested plants in close proximity to multiple divested plants and therefore stabilizes estimates somewhat in comparison to the unweighted approach.

To evaluate the time path of the effect of divestiture, I interact an indicator variable for treatment facilities with dummies indicating the time relative to year of divestiture in Figure 5. The omitted coefficient is the year prior to divestiture. Panel A of Figure 5 is analogous to the average effect in column 2 of Table 2, and panel B of Figure 5 breaks out the results of column 4. Both panels show a flat relative price profile prior to divestiture that is close to, and statistically indistinguishable from, zero. It appears that any changes that occurred after divestiture are not part of a continuation of a pre-existing trend. The corresponding figures at different thresholds share this characteristic (not shown). Because collection from divested plants did not begin until 2002, and most plants were divested in 1999–2000, the vertical line in the figure denotes the year that the EIA began collecting data from most non-utility plants, as described in Section IV. If divestitures led to an immediate change in operations, there would be a jump in the first year after sale. Instead, it appears the gains achieved by divested plants took a few years to settle in to a new, permanent level. This may be due to staggered expiration of contracts written before divestiture, but again it is difficult to draw conclusions based on the handful of plants for which data are available for the first two years after sale. The pattern of reductions for the other specifications are nearly indistinguishable from those in Figure 5, a relatively stable period starting at year three at over 10 percent less than their regulated counterparts.

It is possible to derive the full distribution of treatment effect by estimating separate DID regressions that each include a single divested plant and its respective matches, as the ATT is simply the average of these plant-specific estimates. This distribution reveals substantial heterogeneity in how coal prices have been affected by divestiture, but a median effect (-0.09) that cannot be rejected as statistically equal to the overall average. The 25th and 75th percentiles are -0.21 and 0.02, respectively. Although too fine a description of the heterogeneity is prohibited by nondisclosure considerations, it is possible to say that the largest price drops occurred in Illinois (where 19 plants were divested) and that there is not a particularly strong geographic pattern (West-to-East, for example) determining the magnitude of the treatment effect.

Before examining these results in the light of theories of regulatory inefficiency, it is important to rule out a rather simple hypothesis: that the relative change in price is due to changes in quantities demanded at coal-fired facilities. Repeating the analysis with net generation as the dependent variable shows that this was not the case: there has been no differential change in production between divested and non-divested plants (results available from the author). This may be explained by the fact that coal-fired units tend to be used for "baseload" generation—that is, they run at full capacity at all times except during maintenance periods. While deregulation created the risk market power exerted by withholding generation, it does not appear that coal-fired output was substantially affected on net.

B. *Importance of Asymmetric Information: Comparison with Natural Gas*

We have shown that coal burned for electricity is heterogeneous, and often sold via bilateral contracts. Furthermore, prices are location-specific due to high transportation costs. This makes it difficult for a regulator to know what purchasing opportunities are available to an operator, and whether the operator is exerting sufficient effort to keep costs low. By contrast, natural gas is a homogeneous product (methane, mostly), traded on a transparent market.[24] Since IOUs typically own the complete portfolio of generating plants, gas- and coal-fired facilities were subject to an identical change in regulatory structure. The importance of the interaction of information asymmetry and local capture can therefore be demonstrated by comparing the results for coal prices with those of natural gas.

[24] A set of year-month dummies explains half of the variation in gas prices, but only one quarter of the variation in the delivered price of coal.

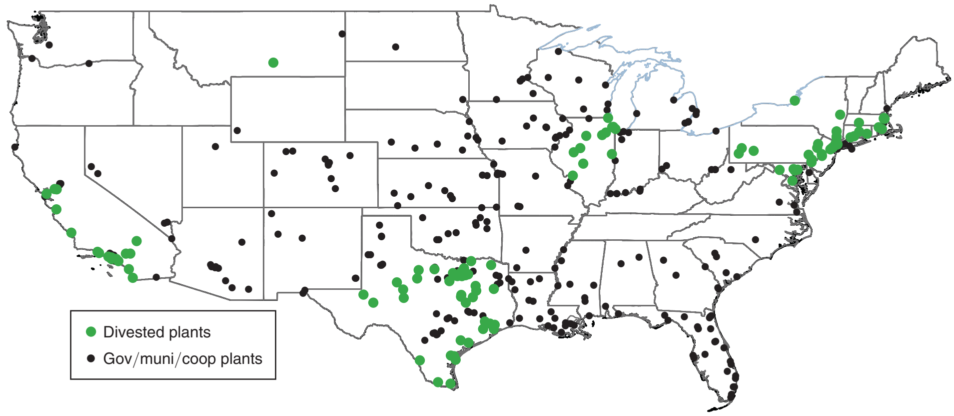

Figure 6. Divested and Control Gas-Fired Plants, 1990–1997

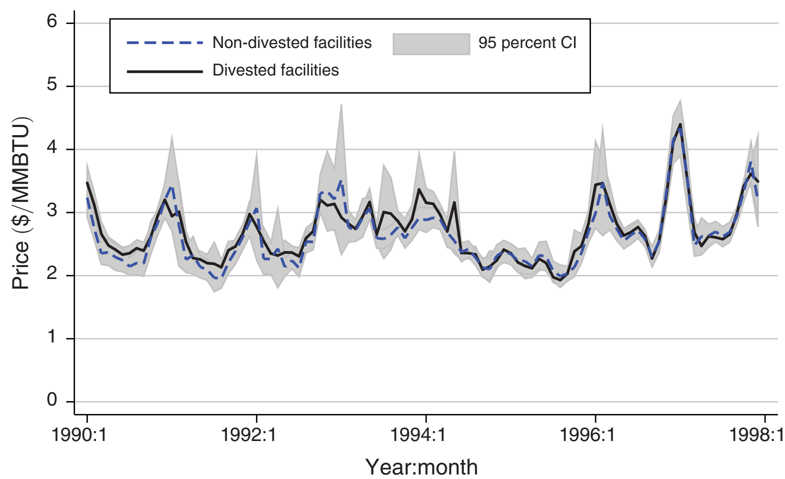

Figure 7. Pre-Trend Test: Matching Estimates of Delivered Gas Price, 1990–1997

Notes: Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility.

Figure 6 shows the analogous map of divested gas-fired plants in the United States as of 1997. It is important to use this baseline because the recent drop in natural gas has lead to a boom in gas-fired generating capacity, much of which was never owned by an IOU, and therefore only began reporting costs in 2002. The key distinction between geographic distributions of gas- and coal-fired plants is that we now include the divestitures of California, which relies primarily on gas and hydro-powered generators. Figure 7 shows the pretreatment trends of prices paid by matched divested and non-divested plants. While gas prices are clearly more volatile than coal prices, divested and non-divested prices co-move; there is no indication of a preexisting differential trend between the groups.

Table 4 shows that divestiture has had essentially zero effect on the price generators pay for gas. This is true regardless of the matching criteria, and is relatively precisely estimated. In the case of gas, regulation was not distorting input price. It

Table 4—Gas: Matched DID Estimates of log(*Price*) and Divestiture

	(1)	(2)	(3)	(4)	(5)	(6)
Post-divest	0.012	0.027	0.010	0.012	0.005	0.038
	(0.026)	(0.029)	(0.036)	(0.027)	(0.027)	(0.038)
m nearest neighbors				10	5	1
Proximity threshold (mi.)	200	100	50			
Year-month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.853	0.852	0.861	0.855	0.857	0.854
Facilities	276	198	111	254	224	165
Divested facilities	109	99	59	109	109	109
Observations	46,828	33,465	17,631	41,089	36,727	26,510

Notes: Dependent variable is log(*Price*) of Gas per MMBTU. Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j subject to the indicated matching criterion. Standard errors clustered by facility in parentheses.

*** Significant at the 1 percent level.
** Significant at the 5 percent level.
* Significant at the 10 percent level.

is important to point out that regulated IOUs operating coal-fired plants also tend to own gas-fired plants in order to meet changes in demand throughout the day. Thus the exact same operators whose coal prices changed substantially following divestiture were unable to make similar improvements for their gas purchases. This implies that differences in the markets for coal and gas play a critical role in determining the potential for cost reductions following divestiture. The defining characteristics that differentiate these markets are price transparency and the room for discretion allowed by commodity heterogeneity, suggesting the importance of asymmetric information in creating the conditions that yield distortions under regulation.

C. *Sulfur Emissions Compliance Decisions*

Title IV of the Clean Air Act Amendments of 1990 capped the total emissions of sulfur oxides (which contribute to acid rain) allowed from major sources (i.e., coal-fired power plants) and created a market so that plants with high abatement costs could buy allowances instead of install abatement equipment. The market began in 1996 for the largest plants, with the remainder of coal-fired plants following soon after. Aside from buying allowances, plant operators had two main options to comply with the new regulations: buy a flue-gas desulfurization system (called a "scrubber") or switch to burning low-sulfur coal, typically from the Powder River Basin (PRB) in Wyoming. The Averch-Johnson hypothesis predicts that regulated plants will prefer to install capital-intensive scrubbers, which will add to their rate base.

Since scrubber installation is a permanent, binary outcome, it does not make sense to employ the matched DID approach described above. The behavior of managers that already have a scrubber installed is also uninteresting. I therefore perform a straightforward matching of divested and non-divested facilities that burned a common rank of coal, but did not have scrubbers installed in 1997. In recent work, Fowlie (2010) finds evidence consistent with the Averch-Johnson hypothesis in the context of compliance decisions for regional nitrogen oxide markets using a random-coefficients

Table 5—Matched DID Estimates of Sulfur Compliance Strategy

	Scrubber	Low sulfur	Uncontrolled
Post-divest	−0.072***	0.100***	−0.032
	(0.024)	(0.031)	(0.038)
Divested unit	0.014	0.010	−0.023
	(0.040)	(0.034)	(0.047)
m nearest neighbors	10	10	10
R^2	0.017	0.049	0.056
Units	384	384	384
Divested units	197	197	197
Observations	7,145	7,145	7,145

Notes: Sample includes all units without a scrubber and burning bituminous coal in 1990. Non-divested units receive weight $\frac{1}{m_j}$ for each matched divested facility j within 200 miles. Matching criterion: $m = 10$. Standard errors clustered by unit in parentheses.
*** Significant at the 1 percent level.
** Significant at the 5 percent level.
* Significant at the 10 percent level.

logit model. By contrast, the approach taken here is nonparametric. The benefit of this approach is that the results are free of the distributional assumptions that may cost more complex estimators some credibility. The main cost is that the structural approach identifies behavioral parameters that can be used to make out-of-sample predictions.

With this caveat in mind, Table 5 compares compliance decisions among generating units that were burning high-sulfur coal in 1997 without a scrubber installed. While divested units are clearly less likely to install a scrubber, the seven percentage point difference masks the magnitude of how big this effect really is. Instead consider panel A of Figure 8, which shows the differential rate of scrubber adoption. It is quite striking that only 3 of roughly 200 divested units install a scrubber up to six years after divestiture. It is only at the end of the sample that scrubber installation begins to pick up at divested units, so that they are about half as likely to install a scrubber by the end of the sample period. This result is relatively consistent across threshold specifications, with the difference being slightly larger when using a distance caliper rather than number of matches.

Instead, divested plants disproportionately chose to comply with sulfur emissions regulations by switching to sub-bituminous coal, as shown in panel B of Figure 8. Since sub-bituminous coal has become relatively cheap in the past decade,[25] it may be that Averch-Johnson-type motives are the source of the observed drop in the price of coal among divested plants. One method of accounting for the role of fuel switching in cost savings estimates is to allow the treatment effect to differ between facilities that have switched the rank of coal they burn, and those who are still burning the same rank of coal as at baseline. Panel A of Table 6 reproduces the baseline estimates of Table 2, allowing for this heterogeneous treatment effect. The overall average price difference among plants that eventually switch is absorbed in the plant fixed-effects. It shows that facilities do in fact realize larger gains after having switched fuels—the total effect among switchers is obtained by

[25] This may be surprising in light of the finding of Busse and Keohane (2007) that railroads exerted market power in the face of greater demand for low-sulfur coal. However, increases in productivity over this period have more than offset demand shocks and markups. See the online data Appendix for a discussion of these trends.

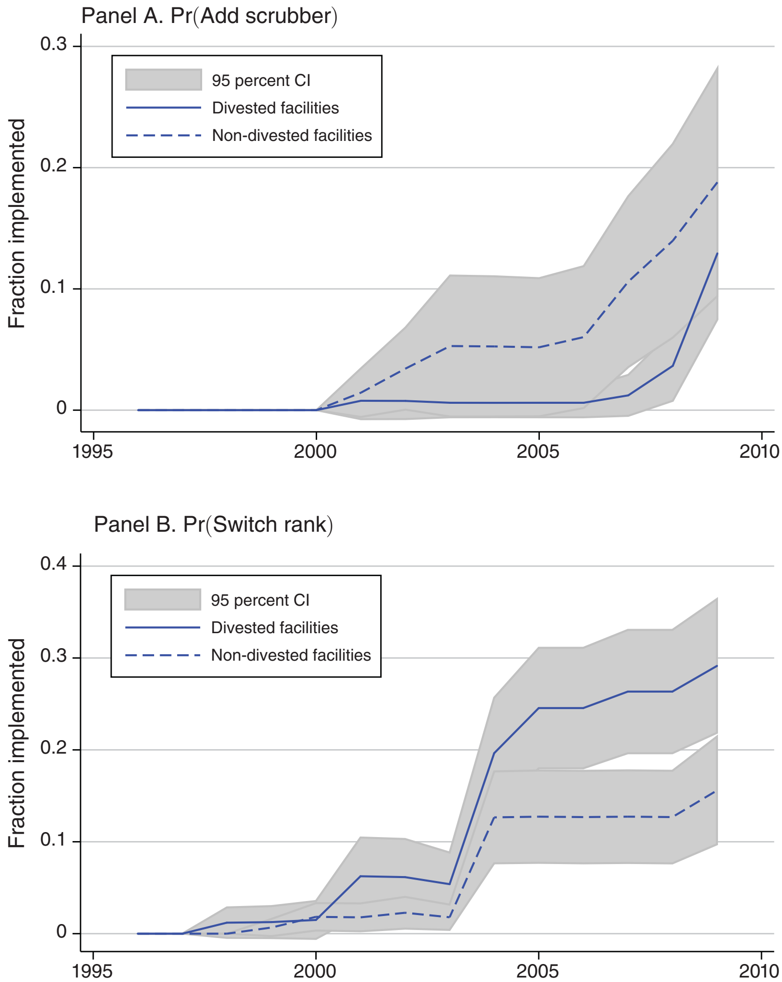

Figure 8. Matching by Year from Divestiture: Sulfur Compliance Strategies, 10 Nearest Neighbors

Notes: Sample is based on units that did not have a scrubber installed in 1997. Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility.

adding the coefficients—though the difference is not statistically significant. This is not due to compositional differences between switchers and non-switchers: all but three facilities report at least one month of post-divestiture fuel purchases using the same rank of coal that was burned in the baseline year 1997. These post-divestiture purchases contribute to the non-switching estimate until the actual switch is made. Perhaps most important is the fact that around 90 percent of the gains seen overall are from facilities that have not switched to low-sulfur coal. While switching yields a larger drop, it accounts for a relatively small fraction of the overall treatment effect. This means that divested facilities were able to find and negotiate for cheaper coal, regardless of any motives to use low-capital methods to comply with sulfur emission regulations. The cost reductions found here are largely not an ancillary

TABLE 6—MATCHED DID ESTIMATES OF LOG(*Price*) AND DIVESTITURE, BY COAL RANK SWITCHING AND IMPORT STATUS

	(1)	(2)	(3)	(4)	(5)	(6)
Panel A. By Low-sulfur switching						
Post-divest	−0.109**	−0.176***	−0.166*	−0.109**	−0.114**	−0.121*
	(0.050)	(0.067)	(0.091)	(0.051)	(0.052)	(0.068)
Post-divest *x* Switching plant	−0.053	−0.038	0.046	−0.052	−0.052	−0.053
	(0.048)	(0.057)	(0.092)	(0.048)	(0.049)	(0.049)
m nearest neighbors				10	5	1
Proximity threshold (mi.)	200	100	50			
Year-month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.721	0.712	0.668	0.724	0.727	0.738
Facilities	230	146	69	198	166	121
Divested facilities	87	74	39	87	87	87
Observations	47,024	28,449	12,682	37,495	32,958	23,336
	(1)	(2)	(3)	(4)	(5)	(6)
Panel B. By Import status in 1997						
Post-divest	−0.157**	−0.244***	−0.250**	−0.157**	−0.161**	−0.169**
	(0.067)	(0.083)	(0.107)	(0.068)	(0.069)	(0.082)
Post-divest *x* Initially in-state	0.066	0.115	0.210*	0.066	0.066	0.066
	(0.068)	(0.081)	(0.113)	(0.068)	(0.068)	(0.069)
m nearest neighbors				10	5	1
Proximity threshold (mi.)	200	100	50			
Year-month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.722	0.715	0.679	0.724	0.727	0.739
Facilities	230	146	69	198	166	121
Divested facilities	87	74	39	87	87	87
Observations	47,024	28,449	12,682	37,495	32,958	23,336

Notes: Dependent variable is log(*Price*) of Coal per MMBTU, including shipping costs. The treatment indicator in panel A is interacted with dummies indicating whether the facility changes the predominant rank of coal burned after 1997. The treatment indicator in panel B is interacted with dummies indicating whether the facility sourced its coal from within its home state in 1997. Main effects are absorbed in plant-level fixed effects. Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j burning the same rank of coal in 1997, subject to the indicated matching criterion. Standard errors clustered by facility in parentheses.

*** Significant at the 1 percent level.
** Significant at the 5 percent level.
* Significant at the 10 percent level.

benefit of more fundamental motives to distort abatement techniques to more capital-intensive options among regulated utilities.

These results also suggest that violations of SUTVA may lead to an underestimate of the effect of divestiture on coal prices, if anything. An overestimate would occur if some activity undertaken by the divested plants led to an artificial inflation of the prices available to the control plants. Instead, the fact that divested plants disproportionately switched to low-sulfur coal means that there was a reduction in the domestic demand for high-sulfur coal, potentially reducing the price of the coal that control plants continued to burn. For compliance decisions themselves, a potential SUTVA violation comes from changes in the equilibrium price of sulfur emissions.[26] An increased propensity to burn low-sulfur coal raises the price

[26] I am grateful to Meredith Fowlie for pointing this out.

of emissions because burning it emits more sulfur than scrubbing. A higher sulfur price raises the attractiveness of adopting the cleaner technology—a scrubber. Note, however, that such price effects occur for all market participants. The net effect of this SUTVA violation will depend on how capital bias changes (if at all) with the price of sulfur because scrubbing becomes more attractive to both divested and non-divested plants as the price of sulfur increases. In addition, such concerns are only salient if the Averch-Johnson effect is, in fact, affecting behavior. If it were not influencing decisions, there would be no divergence in compliance strategies to raise the price of sulfur in the first place.

D. *Regulatory Capture by Local Coal Producers*

A distortion in the spirit of Stigler (1971) and Peltzman (1976) would exist if coal suppliers lobby the state regulator to force generators to buy from local coal mines. However, it is ambiguous a priori whether such a distortion would lead to larger or smaller reductions in fuel prices in coal-producing states following divestiture. While there may be larger potential savings in these states (as predicted by the model), there is also likely to be greater resistance to keep them from being realized. Lile and Burtraw (1998), for example, document efforts undertaken by state legislatures to promote the purchase of local coal, ranging from subsidies to blatant mandates on the percent of coal that must come from within the state. While efforts to legislate such policies were voided by the courts under the Commerce Clause, it is still possible to make life for generators difficult through environmental regulations. Panel B of Table 6 provides evidence suggesting that local coal may have been an impediment to fully realizing the potential savings from divestiture. It allows the effect of divestiture on $\log(\mathit{Price})$ to vary between facilities that bought the majority of their coal from within their home state in 1997 and those who mostly imported. Although facilities that initially imported their coal consistently realized gains across specifications that are about 50 percent greater than plants that bought from within-state, the difference between the coefficients is not statistically significant. Furthermore, this can only be interpreted as suggestive evidence since geographic distance between these groups could also cause differences in cost reductions.

More definitive evidence of inefficient procurement practices in coal-producing states can be seen by examining changes in sourcing after divestiture. Recall that at baseline divested and non-divested plants are relatively balanced on the percent of coal sourced in-state. Table 7 limits the sample to divested and control plants that burned in-state coal in 1997. It measures the change in the fraction of coal sourced from in-state associated with divestiture. Since any plants that switch to sub-bituminous coal will mechanically increase their out-of-state purchases, it allows for heterogeneous effects between plants that switch and those that do not. The goal here is to separate off switching motives from efforts to find lower cost producers that are not protected by state governments. If sourcing practices under regulation were efficient, one might see price drops as generators negotiated for larger fractions of the surplus, but there would be no reallocation of business to different mines. Table 7 shows this was not the case. Instead, divested facilities that initially sourced their coal in-state increased their out-of-state purchases, unconditional upon

TABLE 7—MATCHED DID ESTIMATES OF PERCENT OF IN-STATE COAL AMONG PLANTS BURNING IN-STATE COAL IN 1997

	(1)	(2)	(3)	(4)	(5)	(6)
Post-divest	−0.093	−0.114	−0.111	−0.102	−0.107	−0.160***
	(0.058)	(0.073)	(0.072)	(0.065)	(0.065)	(0.055)
Post-divest x	−0.374***	−0.351***	−0.342***	−0.374***	−0.373***	−0.377***
Switching plant	(0.059)	(0.057)	(0.092)	(0.059)	(0.059)	(0.059)
m nearest neighbors				10	5	1
Proximity threshold (mi.)	200	100	50			
Year-month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.687	0.667	0.689	0.682	0.679	0.718
Facilities	82	68	30	81	74	57
Divested facilities	40	33	15	40	40	40
Observations	17,433	13,745	5,858	16,802	14,707	10,820

Notes: Dependent variable is percent of Coal sourced from in-state. All plants in the sample sourced from in-state in 1997. Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j burning the same rank of coal in 1997, subject to the indicated matching criterion. Standard errors clustered by facility in parentheses.

*** Significant at the 1 percent level.
** Significant at the 5 percent level.
* Significant at the 10 percent level.

switching status.[27] While the biggest changes are among those who switch, there is also some evidence that plants in Pennsylvania, Ohio, and Illinois were able to find lower cost bituminous coal after divestiture (likely from Kentucky and West Virginia), although this effect is only statistically significant in one of the matching specifications. In total, the relative fraction of coal sourced locally falls by about 25 percent during the post-divestiture period.[28] While local coal lobbies may have prevented divested facilities from fully realizing the price reductions achieved in areas without coal deposits, they were not completely successful at mitigating the impact of divestiture on demand for their product.

Among the plants that switch to burning low-sulfur coal, it is not possible to distinguish between the importance of Averch-Johnson and regulatory capture with the current evidence: both theories predict that deregulated plants will be more likely to switch to sub-bituminous coal, which is both lower in cost and capital-intensity. In fact, it is likely that the two forces are mutually-enforcing: eastern coal producers and regulated IOUs both stand to benefit from the installation of a scrubber. It is also not possible to identify the separate effects of asymmetric information and regulatory capture in coal-producing regions. However, the fact that there is no relative price drop for gas suggests that opacity in the market for coal creates the room needed for special interests to exert influence.[29]

[27] The coefficients are not minus one for switchers because this estimate is relative to the matched control facilities (who also switched ranks of coal, albeit at a lower rate).

[28] Figure B.2 of the online Appendix shows that this is not due to spurious preexisting trends: there is a flat pre-trend around zero, and a precipitous fall in the share of coal sourced in-state following divestiture.

[29] For a theoretical treatment along these lines, see Coate and Morris (1995).

VI. Transfers versus Efficiency Gains

The large drop in price observed at divested coal-fired plants says little about the social welfare gains derived from restructuring. Even the substantial reallocation to out-of-state mines is consistent with minimal mining cost reductions. Suppose, for example, that out-of-state mines are only marginally more productive than in-state mines, the latter of which have been receiving regulatory rents. Prices fall and output shifts following divestiture, but to little effect in terms of the resources required to produce electricity.[30]

Fortunately the EIA data on coal deliveries include information on the supplier and county of origin. I have linked these deliveries to characteristics of the mines from which the coal is derived. This includes quarterly data on the labor hours per ton (converted to hours per MMBTU to preserve consistency) from the Mine Safety and Health Administration, the associated wage bill from the Bureau of Labor Statistics, and data on the depth and thickness of coal seams from the US Geological Survey. Seam depth measures how many feet underground must be dug before reaching the coal (to serve as a proxy for fixed costs), and seam thickness measures how much coal per foot of horizontal digging can be recovered once the seam has been reached. Because the marginal ton of coal mined in December is the first mined in January, labor hours can be interpreted as a measure of the average marginal cost of labor, though not marginal cost itself.

Figure 9 shows the effect of divestiture on the mining labor embodied in coal purchases. The difference between divested and matched plants prior to divestiture is relatively flat and insignificantly different from zero in both panels. The hours of labor required to mine coal then drops by about 25 percent for coal that is subsequently sold to divested plants, and this persists throughout the post-divestiture period. While hours drop, wages rise by about 5 percent—suggesting relative labor productivity gains at mines that sell to divested plants. Results are similar when considering the characteristics of the mines from which the coal is being sourced. Figure 10 shows that coal delivered to divested plants comes from seams that are about 30 percent thicker, and nearly 50 percent closer to the surface following divestiture. These results indicate that the shift in procurement following divestiture led to substantial reductions in the cost of mining coal for electricity generation. Whether this is due to productive efficiency improvements within mines, or allocative efficiency gains across them is the subject of ongoing research.

VII. Conclusion

This paper uses two decades of detailed procurement data at gas- and coal-fired power plants to characterize the major determinants of regulatory inefficiency in US electricity generation. I find evidence that asymmetric information, regulatory capture, and capital-bias all lead to substantial distortions in procurement decisions. I find the price of coal drops by 12 percent at deregulated plants relative to similar, nearby coal-fired facilities that were not subject to any regulatory change. Deregulated

[30] The success of special interest groups that advocate for transfers with minimal welfare costs is predicted by Becker (1983, 1985).

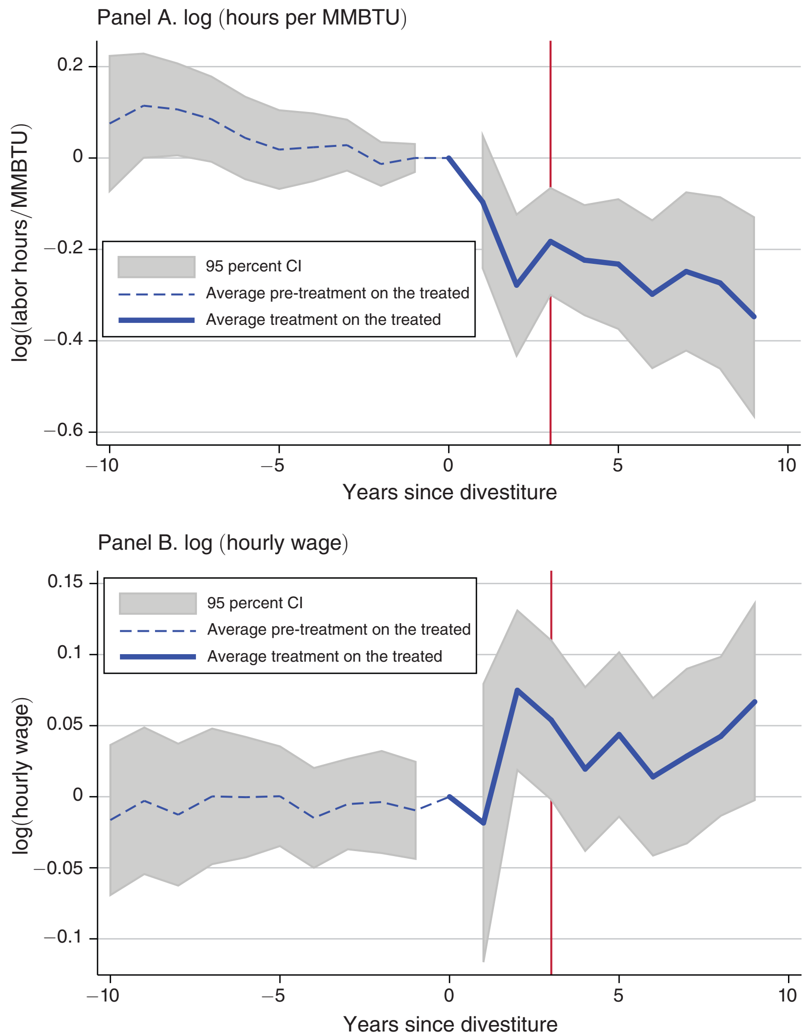

FIGURE 9. MATCHING BY YEAR FROM DIVESTITURE: MINE LABOR

Notes: Hours per MMBTU is the number of hours of labor required to extract 1 MMBTU worth of coal at the mines from which matched plants purchase coal. Non-Divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility. The vertical line denotes the point at which most divested facilities resumed reporting fuel costs.

plants disproportionately switch to burning low-sulfur coal rather than install capital-intensive abatement equipment to comply with environmental regulations and expand imports from out of state by 25 percent if they were initially burning in-state coal. In addition, I find that the reallocation of procurement following divestiture is toward mines that are substantially more productive than those that supply regulated facilities. In total, operators of divested coal-fired plants spend about \$1B less per year on coal due to deregulation. These plants make up only 25 percent of coal-fired capacity, while the rest have continued operating without any change in regulation.

My results do not imply the universal failure of regulators to induce efficient behavior in the regulated community: I find that generators pay the same price for

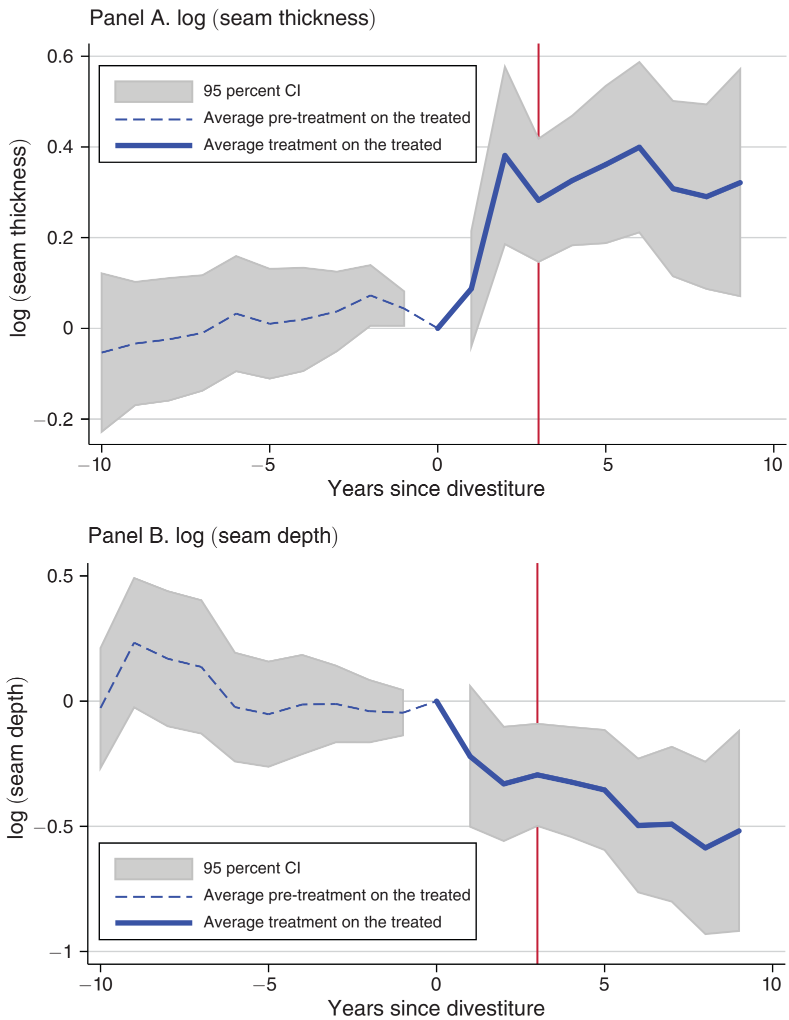

Figure 10. Matching by Year from Divestiture: Source Mine Characteristics

Notes: Seam thickness is the thickness and seam depth is the estimated depth below the surface of coal seams at the mines from which matched plants purchase coal. Non-divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility. The vertical line denotes the point at which most divested facilities resumed reporting fuel costs.

natural gas regardless of their regulatory status. Instead, this indicates that regulation may work well when the regulated community is unable to shroud its inefficient behavior from oversight.

After 30 years of deregulation, the pendulum is swinging back toward greater government oversight in order to correct market failures in critical sectors of the American economy such as finance, banking, and health care. In addition, the deregulatory momentum of the 1990s has stalled in the electricity sector following the 2000–2001 crisis in California. Although regulation may appear at first to be the solution to imperfect markets, as eloquently described by Bastiat (1850), this is not the end of the story.

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