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Abstract

When deciding whether to introduce market competition in a regulated industry, a regulator faces an important tradeoff. Market-based prices can provide incentives to allocate resources more efficiently and reduce costs, but the presence of market power may lead to increased markups. We construct a novel dataset on electricity generation, wholesale transactions, and retail sales to investigate the impact of deregulation in the context of the U.S. electricity sector. We find that the higher markups charged by generation companies more than offset the efficiency gains, leading to higher wholesale prices. Downstream, incumbent utility retail prices rose one-for-one with the increase in variable costs of procurement, while the introduction of alternative retail suppliers generated modest retail markups for some customers. These results highlight the role of market power in deregulated markets, and show that consumers may prefer regulated prices to market-based prices when markets are not perfectly competitive.

Keywords: Deregulation, Market Power, Markups, Prices, Electricity
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1 Introduction

Organizations that make large investments in broadly used infrastructure are often subject to special regulation. These organizations are typically characterized as natural monopolies, and regulation has been used to ensure the fair provision of services in the absence of competition. Industries such as electricity, airlines, telecommunications, and railroads have been subject to strict controls by governmental agencies, including the determination of prices. Over the past 50 years, technological progress and other factors changed how policymakers viewed many of these industries, leading to waves of deregulation. A common element of deregulation efforts has been the introduction of free entry and market-determined prices, with the goal of lowering prices to consumers.

However, the impact of deregulation on prices is theoretically ambiguous. Market-based prices provide incentives for profit-maximizing firms to reduce costs, but they also can provide firms with the ability to increase markups. When cost efficiencies are outweighed by the presence of market power, market-based prices can be higher than regulated rates. Thus, deregulation can lead to higher profits and lower consumer welfare.

We study the tradeoff between efficiencies in production and increased markups in the context of the restructuring of the U.S. electricity sector that started in the late 1990s. A significant objective of restructuring was to promote market-based—as opposed to regulated—prices in wholesale and retail markets. Toward this end, policymakers oversaw the divestment of generation facilities by regulated utilities and the introduction of alternative retail suppliers. Over 20 years later, we have yet to fully understand the consequences of these deregulation efforts (Bushnell et al., 2017). Previous studies have found that generation costs declined in deregulated markets (Fabrizio et al., 2007; Davis and Wolfram, 2012; Cicala, 2015, 2022), but the evidence on the impacts on prices is less conclusive (Borenstein and Bushnell, 2015; Bushnell et al., 2017). Contrary to the objectives of deregulation, we show that prices increased in deregulated markets, despite modest reductions in marginal and average variable costs. Markups increased substantially, indicating the widespread exercise of market power in U.S. electricity markets and highlighting the potential costs of deregulation.

To understand how markups changed in the electricity sector, we construct a novel dataset that covers the annual electricity flows from generation to final consumption for each electric utility territory from 1994 through 2016. Our dataset has the unique advantage of including purchases through bilateral contracts, in addition to purchases in the centralized wholesale markets run by independent system operators (ISOs).[1] From 2000 through 2016, the vast majority—over 85 percent—of wholesale electricity was sold with such contracts. Thus, a key contribution of our paper is to provide a more comprehensive view of prices in upstream and downstream markets, as that allows us to better understand the mechanisms behind higher

[1] The focus of the previous literature has been on the centralized wholesale markets. See, e.g., Borenstein et al. (2002); Puller (2007); Mercadal (2022).

prices and markups.

Using these data, we compare utilities that were subject to state-specific deregulation policies to similar utilities in other states that remained tightly regulated with a difference-in-differences matching approach (Deryugina et al., 2019). This approach has two important elements that allow us to measure the price effects of deregulation. First, policy variation at the state level allows us to observe both deregulated and regulated markets over the same time period. Second, our dataset allows us to match individual utilities based on generation technology, controlling not only for initial differences but also exposure to differential cost shocks in the future.[2] We then study how prices, costs, and markups have evolved across comparable utilities.

We find substantial price increases for consumers in deregulated states relative to consumers in regulated states. However, consistent with earlier findings, marginal costs declined in deregulated states, indicating that higher prices are driven by higher markups. Overall, we estimate that gross markups—retail prices minus the marginal cost of generation—increased by 15 dollars per MWh from 2000 to 2016. Relative to 1999 price levels, this change in markups corresponds to a 19 percent increase in prices over the period. Using our comprehensive data on wholesale markets, we find that wholesale prices increased despite declining generation costs. Thus, markups by generators increased by roughly 9 dollars per MWh, representing over 60 percent of the overall increase in gross markups. Thus, we find market power in the generation market to be the primary driver of price increases.

For a clearer picture of the mechanism behind prices increases, we focus in on the procurement costs for incumbent utilities. During the early years of deregulation, utilities faced higher procurement costs despite little change to generation costs and market prices. Because of the divestiture of generation assets, utilities were forced to obtain more electricity from purchases rather than own generation, and wholesale prices were higher than generation costs. The rates that incumbent utilities charged to their customers—which remained regulated to reimburse average variable costs—went up due to the introduction of this markup, which is analogous to double marginalization.

Several years later, around 2005, wholesale prices began to increase even though generation costs started to fall. Why? When states passed deregulation measures, they also adopted provisions to make the transition less sudden for consumers. Key provisions were price caps and long-term procurement contracts. When these expired (around 2005), utilities no longer had the bargaining power to insist on low wholesale prices. Generators could now sell to ISO markets or retail power marketers, and prices were no longer tied to price caps to downstream consumers. As a result, generators charged utilities more for their contracts, and wholesale prices increased. If there had been no market power, we would instead expect wholesale prices to fall along with the decline in generation costs.

[2]Fuel mix, for example, greatly determines how generators will be affected by shocks to fuel prices.

It is important to note that we measure market power using markups, the difference between price and marginal cost. In order to distinguish market power from competitive rents, which could arise in a competitive market in the presence of cost heterogeneity, we use a proxy for the marginal cost at the market level. In a competitive market, individual plants may have prices above marginal costs if a higher-cost plant determines the market price. However, the most expensive plants should not earn meaningful markups if the market is competitive. Consistent with market power, we find substantial increases in markups over the highest-cost plants.

Market power can exist even with competitive market mechanisms, such as auctions, when there are a limited number of potential suppliers. The previous literature has documented market power in electricity markets (e.g., Borenstein et al., 2002; Puller, 2007; Bushnell et al., 2008; Ito and Reguant, 2016; Mercadal, 2022), but its overall impact on consumers has not been studied. Several characteristics of electricity make these markets particularly prone to market power (Borenstein, 2002). Both demand and supply are inelastic, yet supply must meet demand at every moment since large amounts of electricity cannot be stored efficiently. Transportation is expensive, constraining the degree to which generators compete across local markets (Ryan, 2021; Mercadal, 2022). Entry is limited due to large sunk investments, long planning horizons, and high risk. As a result of these factors, only a few generators are typically competing to serve demand for a certain area at a particular moment, and the relative scarcity can give them substantial market power. Deregulation did not fundamentally change these factors.

We present several indirect tests of market power that point to market power at the wholesale level as the main driver of price increases. First, concentration among generators remained constant at high levels between 1995 and 2015. Higher markups did not attract significant entry, which is consistent with the presence of significant entry barriers. Second, states with lower potential competition saw bigger markup increases. Finally, we show that markups increased more in markets with more inelastic demand, as measured by the proportion of residential consumers.[3] Taken together, these findings support market power as the main driver behind our results.

We also show that the market restructuring intended by deregulation was delayed for several years. Despite the divestiture of generation assets, utilities maintained a high degree of vertical integration through contracts and umbrella ownership, where different companies are subsidiaries of the same parent/holding company. Thus, we distinguish between *apparent deregulation*—the share of a market supplied by companies other than the incumbent utility—and *effective deregulation*—the share of a market supplied by companies unaffiliated with the incumbent.[4] In wholesale markets, we find that the use of contracts delayed the onset of effective

[3]Residential customers tend to be less sensitive to prices than industrial and commercial customers. For instance, they are more likely to stay with the incumbent, even at higher prices, after retail competition is introduced.

[4]We use the term "affiliate" as a company belonging to the same parent company.

deregulation by many years, compared to apparent deregulation. In retail markets, caps on rates and other factors slowed the introduction of competitive retailers. Consistent with these delays, we observe a larger impact on prices once restructuring measures are fully in effect. Thus, distinguishing between apparent deregulation and effective deregulation can be important to accurately measure policy impacts.

We believe we are the first to document the extent to which electric deregulation in the U.S. yielded higher prices and to present evidence of an underlying mechanism: market power at the wholesale level that dominated cost efficiencies. Though there was early awareness of the potential for market power in deregulated markets,[5] the fact that the effects of market power could considerably exceed the savings from increased cost efficiency is surprising. Moreover, our analysis shows that contracts play a key role in market dynamics since they explain why we observe the effects of deregulation with a delay.

The existing literature on the consequences of deregulation is surprisingly scarce, given the importance of the electric sector for the economy and decarbonization efforts. The literature has documented gains in productive efficiency in several dimensions. Fabrizio et al. (2007) show that restructured plants reduced costs through better plant operation, spending less on labor and nonfuel costs for a given level of output. Davis and Wolfram (2012) also find better operational performance for deregulated nuclear plants, which increased output by 10 percent. Cicala (2015) shows that procurement costs decline in gas and coal plants after deregulation. Finally, Cicala (2022) shows that costs have also declined because of more efficient dispatch after ISOs were established to coordinate the usage of transmission and increase inter-utility trade. Our results on costs are consistent with this literature, since we also find moderate declines in fuel costs for power plants in restructured states.

However, the existing literature on restructuring has not yet determined whether these cost reductions have translated into lower prices for consumers. In a review of the literature, Bushnell et al. (2017) conclude that the effect is unclear. Findings differ across studies due to the differences in time periods, the use of different methods, switching focus between wholesale and retail prices, and the inclusion of other price determinants like stranded costs, among others (see, e.g., Joskow, 2005; Kwoka, 2008b; Su, 2015). Our dataset has the advantage of covering the whole industry, measuring flows from generation to retail, spanning a period of over 20 years, and capturing both costs and prices. This allows us to present a clear picture of the changes underwent by the industry, and using detailed firm-level data allows us to account for some of the confounding factors that are common concerns in the literature.[6]

[5]For example, Borenstein and Bushnell (2000) write “Market power among generators is likely to be a more serious and ongoing concern than has been anticipated by most observers,” due to the combination of “inelastic short-run demand and supply (at peak times) with the real-time nature of the market.”

[6]Although the deregulation process varied across countries, studies of the consequences of deregulation in other markets have found results that are consistent with ours. Newbery and Pollitt (1997) finds that costs went down after the restructuring of the electricity market in the UK in the 1990s, but prices barely decreased, leading to a substantial increase in profits. Bertram and Twaddle (2005) analyze the evolution of price-cost margins in New Zealand

Borenstein and Bushnell (2015) examine the consequences of restructuring between 1998 and 2012 and argue that the prices differences are primarily explained by differential responses to higher natural gas prices, which significantly affect marginal costs but not as much average costs. We consider this possibility, yet we find an increasing gap between prices (which increase) and marginal costs (which decrease) in markets after deregulation. In particular, natural gas prices fell in the latter half of our sample. Thus, changes in fuel costs do not seem to explain the rising prices observed in deregulated states. We conclude instead that increasing markups suggest the presence of market power.

The role of vertical integration in electricity markets has been discussed by Bushnell et al. (2008) and Mansur (2007), who show that spot wholesale electricity markets are more competitive when generators are vertically integrated because they have fewer incentives to increase prices. Our paper complements these finding by examining the market as a whole instead of focusing on the spot market, which, as of 2016, made up less than 25 percent of the entire wholesale market. We further add to the literature by examining the role of intermediate degrees of vertical integration. Previous studies in the transaction costs literature have identified the potential substitutability of long-term contracts and vertical integration (e.g., Coase, 1960; Joskow, 1987; MacKay, 2022). Here, we demonstrate how such alternative arrangements may be employed to side-step the intended effects of regulatory policies.

The paper proceeds as follows: Section 2 provides a background of deregulation efforts. Section 3 describes our dataset and key summary statistics. Section 4 details our empirical strategy and provides our main results for prices, costs, and markups, as well as a discussion on the mechanism. Section 5 presents supporting evidence for the role of market power in deregulated markets. In Section 6, we discuss the timing of the observed effects, explore the role of contracts in delaying deregulation effects, and provide a detailed case study on Illinois to illustrate how effective deregulation may be delayed. In Section 7, we explore several possible alternative mechanisms, and we conclude that our findings are most consistent with the exercise of market power. Section 8 concludes.

2 Background

2.1 Overview of Deregulation Efforts

In the 1970s and 1980s, a wave of deregulation encouraged entry and allowed market-based prices in many industries that had been considered natural monopolies, such as telecom, airlines, and surface freight.[7] Although the details of the deregulation process varied across indus-

after deregulation and show that cost decreased but prices increased in the decade following market restructuring. Our approach exploits detailed utility-level data in both deregulated and regulated markets during the same period, allowing to better control for other factors affecting costs and prices during the period under study.

[7] Market-based prices are those determined by demand and supply, as opposed to cost-based prices determined by a regulator as a function of cost.

tries, the principles motivating this process were the same: reduced entry barriers and market competition will increase efficiency and reduce prices. There was a consensus that some industries had undergone significant changes in their cost structures, allowing for beneficial effects of competition. In telecom, major changes in demand and technology had moved the sector away from a natural monopoly, making it an obvious candidate for deregulation.

Many of these deregulation efforts have been considered successful because prices have fallen, though in some cases at the cost of reduced quality (Borenstein and Rose, 2014; Viscusi et al., 2018; Joskow, 2005). However, even in successful cases, these industries remain highly concentrated, often appear in controversial merger cases, and engage in behavior that raises concerns about market power (Borenstein, 1989; Borenstein and Rose, 1994, 2014; Viscusi et al., 2018). For example, after the deregulation of airlines and the subsequent fall in prices, concentration increased (Kahn, 1988) and continued to increase afterwards. Telecom also remains highly concentrated, even after significant growth in demand and technological improvement (Viscusi et al., 2018). High levels of concentration suggest that market power may be an important concern in deregulated industries, where characteristics like high fixed costs or network economies that once led them to be regulated may make them prone to market power. For example, Rubinovitz (1993) finds that over 40 percent of the price increase after deregulation in cable markets in the United States was due to the exercise of market power.

The next section describes how competitive markets were introduced in the electricity sector and provides a brief background of the overall deregulation process.

2.2 Deregulation in U.S. Electricity Markets

Traditionally, electric utilities in the U.S. and the world were vertically integrated companies that included generation, transmission from power plants to towns and cities, distribution along power lines to final consumers, and retail sales to these consumers. Because electricity was considered a natural monopoly, a single utility served each local market, and electricity prices were regulated to avoid monopoly pricing. Utilities were reimbursed based on their average costs of generation. Following a wave of what was considered successful deregulation in other sectors, the electricity sector started its own process of deregulation in the 1990s.

The decision to implement competitive markets occurred at the state level and was determined by local politics (Borenstein and Bushnell, 2015).[8] Though specific implementation details varied across states, state-level deregulation typically involved two main components. The first was vertical separation: most states required utilities to divest some or all of their gen-

[8]On average, states that passed deregulation measures had higher pre-deregulation rates than those that remained regulated, but the decision to deregulate was not necessarifly driven by price differences. For example, IOUs in deregulated states like Oregon and Texas had lower-than-average rates, while some states with higher rates like Vermont and Florida remained regulated. Within states, there is meaningful variation in rates offered by different utilities, resulting in a weaker relationship between deregulation and pre-deregulation prices at the utility level.

eration assets to encourage the creation of a competitive generation sector.[9] As we show in the paper, states varied in how strict the separation between utilities and generation was required to be, and in many cases utilities split themselves into generation and distribution subsidiaries under the same parent company. After deregulation, utilities and alternative retailers in deregulated states procured all electricity from wholesale markets, either through long-term contracts or in a centralized auction organized by transmission operators.[10]

The second major component of the process was the introduction of market-based prices. In restructured markets, prices were no longer dictated by the regulator based on costs, but instead determined by market forces. At the wholesale level, contract prices were determined by mutual agreement between buyer and seller, and centralized auctions cleared at the lowest price at which supply would meet demand. At the retail level, market-based prices included the introduction of competitive retailers who could sell energy at unregulated prices to final consumers. Partly because of uncertainty about whether deregulation would be effective and whether consumers would be protected from high prices, states differed in how they implemented retail competition. Twenty years later, a substantial share of industrial and commercial customers have switched to competitive retailers, but, in most states, the large majority of residential consumers still purchased from the incumbent utility.[11] Typically, incumbent utilities were still required to offer "bundled service," in which they provided electricity at regulated rates in addition to the delivery services that they also provided for competitive retailers.[12]

To ease the transition to deregulated markets, many states implemented caps that limited the rates utilities could charge for customers for several years. States that implemented these programs included Connecticut (expired in 2004), Delaware (2005), Illinois (2006), Maryland (expired between 2004 and 2008), Massachusetts (2004), and Virginia (2006). Along with the price caps, utilities typically signed long-term contracts with the newly divested generation facilities with terms that matched the rate caps. These contracts and price caps play an important role measuring the effects of deregulation, which we address in Section 6.

Deregulation was expected to bring increased efficiency by providing incentives to reduce costs, since under market-based prices lower costs translate into higher profits. Evidence indicates that in fact power plants are both operated more efficiently (Fabrizio et al., 2007; Cicala, 2015) and dispatched more efficiently (Cicala, 2022). Although previous research has found

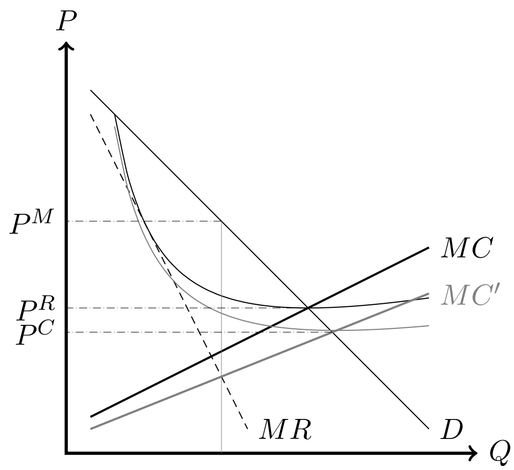
[9] Competitive generation was allowed in a limited fashion since 1978 (Public Utility Regulatory Policies Act, known as PURPA), but entry was limited due to the lack of incentives for utilities to purchase from new entrants or to share transmission assets with competing generation facilities.

[10] There were initially six centralized markets organized by independent system operators (ISOs), the entities in charge of coordinating the use of transmission assets. These are the California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), the New York ISO (NYISO), the New England ISO (NEISO), the Midwest ISO (MISO), and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). Prior to the implementation of ISOs, several markets operated power pools, which served a similar function.

[11] See Hortaçsu et al. (2017) for a discussion of the causes of this phenomenon.

[12] Competitive retailers were able to make use of the distribution grid to sell directly to end consumers. Their consumers paid a regulated distribution rate to the utility, in addition to paying for the electricity from the retailers.

Figure 1: Market-Based and Regulated Prices



Notes: Figure illustrates how market power could increase prices in deregulated markets, despite the presence of cost efficiencies. The thick black line labeled MC plots the marginal cost curve under a regulated regime. The regulated prices are set to reimburse average costs, which are plotted with the thin black curve (unlabeled). With efficient investment, average costs equal MC at the intersection with the demand curve, D, resulting in price P^R. Cost efficiencies from deregulation are illustrated with a downward shift in the marginal cost curve to the thick gray line MC'. In a competitive market, prices will equal $P^C < P^R$. With market power, firms could raise prices up to P^M, which is determined by the intersection of MC' and the marginal revenue curve, MR.

evidence of significant market power in deregulated electricity markets (Borenstein et al., 2002; Puller, 2007; Mansur, 2007; Ito and Reguant, 2016), the literature so far has paid less attention to the role that market power may have in translating this efficiency gains into lower prices for consumers. This paper helps to fill this gap.

Figure 1 illustrates how market power could increase prices in deregulated markets, despite the presence of cost efficiencies.[13] The market demand curve is plotted by the black line labeled D. The thick black line labeled MC plots the marginal cost curve under a regulated regime. The regulated prices are set to reimburse average costs in the market,[14] which are plotted with the thin black curve. With efficient investment, average costs equal MC at the intersection with the demand curve, resulting in regulated price P^R.

In competitive markets, profit incentives could lead firms to more efficiently allocate the supply of electricity. These potential cost efficiencies are illustrated with a downward shift in the marginal cost curve. The new marginal costs are plotted with the thick gray line MC'. In a competitive market, prices will be determined by the intersection of the demand curve with the marginal cost cure, resulting in price $P^C < P^R$. With market power, firms could raise prices up to P^M. P^M is the monopoly price and is determined by the intersection of MC' and the marginal revenue curve, MR. In this figure, deregulation could result in prices ranging from

[13]While this figure does not take into account cost heterogeneity, which is characteristic of electricity markets, the measure of costs used in our empirical analysis does.

[14]For the purposes of the figure, average costs include a fair rate-of-return on capital.

P^C to P^M, depending on the degree of market power.

Based on the motivation for deregulation efforts, the regulator's problem can be cast as a decision between regimes in order generate the lowest retail prices.[15] Overall, whether retail prices increase or decrease after restructuring is an empirical question, depending on the relative importance of efficiency gains and market power.

2.3 Market Power in Electricity Markets

Despite electricity being a homogeneous product, suppliers can have substantial market power. Transportation over long distances is expensive, which limits the effective size of geographic markets. Further, large amounts of electricity cannot be stored efficiently. Thus, supply and demand for a particular location at a particular point in time can be quite inelastic, providing individual suppliers with opportunities to exercise market power.

In centralized ISO auctions, market power is present when suppliers shade their bids upward above their true marginal costs. The degree to which suppliers can do so depends on the rival sources of generation that can provide to that particular market for that particular time window. Prices for bilateral contracts, which represent the vast majority of wholesale electricity transacted, may also reflect restrictions on procurement imposed by public utility commissions. While such restrictions may have a benefit (e.g., a greater share of renewable energy), they often serve to reduce potential competition for a contract and increase market power. For example, it is generally understood that one reason why prices rose sharply in Illinois at the beginning of deregulation was due to poor auction design.

Previous work in the literature has shown significant degrees of market power among generators (Puller, 2007; Hortaçsu et al., 2017; Borenstein et al., 2002; Mercadal, 2022). During the crisis in California at the beginning of its deregulation process, for example, all generators had market shares below 10 percent and still were able to charge markups of around 100 percent (Borenstein et al., 2002; Borenstein, 2002). For prices to fall, substantial efficiency gains would be required to compensate for markups of this magnitude.

Indeed, the example of California is illustrative because it happened at the beginning of the restructuring process, when utilities still retained significant market power. The restructuring process lead to changes in market structure that changed the balance of market power between buyers and sellers. For instance, the introduction of retail competition could allow generators to charge larger markups, as a greater number of buyers in the wholesale market can increase the relative bargaining power of generators. Section 5 documents that, in fact, concentration among buyers has decreased in deregulated markets, while concentration among sellers has remained constant.

While nationwide deregulation measures facilitated the exchange of electricity across geographic markets, local deregulation did not do much to increase within-market competition.

[15] We provide a simple formalization of this problem in Appendix B.

Utilities tended to sell of their entire portfolio of generation to a single new entity.[16] Further, there was limited entry of independent generators over time. Thus, generating facilities in deregulated markets did not realize a meaningful increase in local competition.

3 Data

3.1 Dataset Construction

To measure prices and markups, we use annual measures of generation, purchases, and retail sales within each utility's distribution territory. We obtain measures of quantities (MWh) and expenditures, allowing us to calculate average generation costs, average wholesale prices, and average retail prices. Our data accounts for the fact that, while the structure of the deregulated market changed, the geographical territories for distribution essentially remained unchanged, and the ultimate delivery of electricity to consumers continues to be the responsibility of the incumbent utilities.

We construct our unique dataset from several sources. Our main sources of data are reports provided by the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC) from 1994 through 2016. These reports are publicly available, though they have not previously been combined at this level of detail. Utility-level aggregate data on generation, purchases, and sales is obtained from the operational data in form EIA-861. Form EIA-861 also provides more detailed measures of retail sales, which we use to construct state-specific measures of bundled service and delivery service for each utility. Bundled service refers to the provision of energy and its delivery using the utility's distribution grid; delivery service is the delivery of energy sold by a competitive retailer using the utility's grid. Form EIA-860 collects operational information on power plants, which we use to measure entry and exit of generation capacity.

Detailed data on purchases of electricity is obtained from FERC Form 1, which includes both purchases from centralized auctions and bilateral contracts. One of the key contributions of our data collection effort is to also incorporate bilateral contracts into the empirical study of electricity wholesale markets. These data are used by public utility commissions to set rates and are subject to audits. In addition, we augment the transaction-level data with information on firm ownership structure to construct an indicator of whether a purchase is made from an affiliated company. We use this measure to track what fraction of total sources obtained by a utility come from the same parent company versus independent suppliers.[17] The data on ownership structure was manually constructed from a combination of sources, including

[16] "The fact that these assets (power plants) were sold in large lots, sometimes entire power systems to a single buyer, demonstrates the greater concern regulators placed on vertical than horizontal market power." (Ishii and Yan, 2007)

[17] We are also able to use this data to measure the share of sources coming directly from the markets run by the Independent System Operators (ISOs).

current corporate structure from S&P Global, data on corporate structure, name changes, and mergers and acquisitions collected by the Edison Electric Institute (Edison Electric Institute, 2019), and manual Google search for confirmation.

Deregulation measures were implemented by 21 states in this period.[18] This definition includes measures that introduced market-based prices at the wholesale or wholesale and retail levels, and vertical separation measures including the strengthening of the wholesale market and free entry. Four states—Arizona, Arkansas, Nevada, and Montana—initially passed deregulation measures but later rescinded them. We remove them from our sample. We also remove Hawaii and Alaska, as the electricity infrastructure in these states is quite different from the rest of the United States. Finally, because Nebraska and Tennessee do not have investor-owned utilities with generation resources, they are not included in the sample. Thus, our sample of utilities covers 17 states that implemented deregulation measures and 25 states that did not. For additional details, see Appendix A.

3.2 Unit of Analysis and Key Variables

The unit of analysis in our study is the service area covered by investor-owned utilities (IOUs) in each state. Electric service in the United States is provided by three types of entities: IOUs, nonprofit cooperatives, and public utilities. IOUs were the primary target of deregulation measures—because they could make profits, were substantially larger than other types of utilities, and provided the vast majority of electricity service. In 1994, the 250 IOUs provided 75 percent of generation and 76 percent of retail service in the United States.[19] Since investor-owned utilities are subject to different regulations across states, we treat each utility with service areas in different states as separate utility-state entities. For some parts of our analysis, we will consider the state-wide electricity "market," as all utilities in that state are under the jurisdiction of the same state-specific regulatory commission.

Though deregulation measures ended generation and retail service for several utilities in our sample, these utilities continued to own and operate distribution lines and provide delivery service to retail customers. Because our focus is on the impact to consumers, we define our unit of analysis as each utility's service area. Service areas (i.e., the distribution infrastructure) are quite stable over time. For a visual representation of the geographic coverage of these areas, see Figure A1 in the Appendix. We also account for mergers of utilities throughout our sample period; if utilities merge at any point, we treat them as a single merged entity throughout our sample. For our analysis, we focus on utilities that had generation resources in 1994, at the

[18] Our sample of states that deregulated includes Rhode Island, New York, California, New Hampshire, Massachusetts, Pennsylvania, New Jersey, Delaware, Maryland, Connecticut, Illinois, Maine, Ohio, Texas, Virginia, Oregon, and Michigan.

[19] In 1994, 3,207 utilities reported to the EIA. The remaining 2,957 utilities that were not IOUs consisted of 2,194 municipal utilities and cooperatives, which tended to be much smaller, and 156 publicly run power authorities at the federal, state, or subdivision level.

beginning of our sample. Our final sample consists of 154 merged IOUs that provided over 70 percent of generation and over 70 percent of retail service in 1994.

The key outcomes of interest are retail prices, wholesale prices, and costs. For our primary measure of retail price, we use the "default" price available to residential, industrial, and commercial customers of a utility. We construct this measure by taking the average price for bundled service for each customer type and weighting these measures by the share of consumption by each customer type in the service area. Thus, we adjust for the fact that the composition of customers electing retail service from competitive sources changes over time. For Texas and Maine, several utilities no longer provide bundled service; for these utilities we instead use the average bundled price offered by all retailers in the state.[20]

For wholesale prices, we use the (weighted) average price for purchased electricity by each utility, which we obtain from the detailed transaction data in FERC Form 1. This measure has the advantage of reflecting demand and supply conditions that are local to each utility's service area. We also use these transaction data to capture the share of purchases that come from ISOs and affiliated companies.[21]

For generation costs, we use generator-specific fuel receipts data from EIA to construct a measure of marginal costs. For each utility, we sort its associated generation facilities by fuel costs. We then measure marginal costs as the average fuel cost for the 75th through 100th percentile of MWh generated.[22]This measure captures the marginal cost at the market level, i.e., the marginal cost of the marginal plant. We use the most expensive plants (instead of the average variable cost across all plants) because these plants are most likely to supply the marginal unit of electricity and their costs would determine prices in perfectly competitive markets. Thus, markups over this measure of marginal cost reflect market power and not competitive rents or profits. We use a range of costs (rather than, e.g., the 100th percentile) because the marginal unit varies over the course of the day and over the year. Our results are not sensitive to the lower-end percentile used in this calculation; we obtain similar results for changes in markups if we use the 60th-100th or 90th-100th percentiles instead. With the 75th-100th percentile, marginal costs are approximately equal to wholesale purchase prices in the pre-deregulation period, which we view as a reasonable starting point to test for market power after deregulation.

Our primary measure of costs uses, for each service area, all generators that were owned by the utility at the beginning of our sample (in 1994). That is, we ignore changes to ownership over time that may have been brought about as a result of deregulation. Thus, we preserve a

[20]Throughout, we consider annual quantity-weighted prices as our analysis focuses on price levels. Utilities differ in terms of how much electricity prices can vary month-to-month or with consumption. Existing evidence suggests that consumers are not particularly responsive to such variation (Ito, 2014; Deryugina et al., 2019).

[21]Our measure is somewhat conservative in that a utility may sell generation to a power marketer who then supplies electricity to a delivery customer of the utility. We cannot track this in the data, but if we could it would increase our measure of affiliated purchases.

[22]Before constructing the measure, we winsorize individual generator fuel costs at the 99th percentile.

proxy for generation costs that are specific to each utility's service area. The set of generators are reasonably stable over time; three-fourths of these generators appear in at least 20 years of our sample. To account for investment in new generation resources, we also calculate marginal costs at the state level using the 75th to 100th percentile of costs across all (current) utility and independent power producer generation facilities within the state. We consider retail markups, wholesale markups, and gross markups (retail prices minus generation costs) using these measures. For some analyses, we also consider average variable fuel costs across all generation units, which provides a more accurate measure of profits/rents.

When the unit cost of a given fuel at a specific power plant is not available, we impute it using the average unit cost for that fuel in the state and year; we then use plant-specific measures of fuel consumption and generation to calculate fuel cost per MWh. To the extent that within-state procurement costs for particular fuel types are correlated, this imputation will not affect our results. Due to reporting requirements, our measure of fuel costs in deregulated states comes disproportionately from smaller municipal utilities and coops,[23] which typically have higher procurement costs than the larger generation companies. Thus, our measure can be interpreted as an upper bound on costs. As we will see in the next section, our findings would only change if fuel costs for deregulated generators rose much faster relative to those for municipalities and coops, which we think is unlikely.

3.3 Summary Statistics

In this section, we provide some summary statistics of key variables in our sample. We identify similarities and differences between the treated and control utilities in our sample, where treated utilities are those in deregulated states. Some of the differences motivate our nearest-neighbor matching approach, which we describe in Section 4.

Table 1 shows the key variables for treated and control utilities in 1994. Column (1) reports the mean across the 78 IOUs in the deregulated states, and column (2) reports the mean across the 76 IOUs in the control states. Overall, utilities in deregulated and control states were similar in size in 1994, in terms of retail and generation output. There are some differences in generation mix across the two groups, in terms of the marginal generation units (75th-100th percentile by fuel cost). Markets in deregulated states were more likely to rely on oil (0.19 versus 0.07). This gives rise to a difference in marginal fuel costs, which are substantially larger in deregulated states in 1994. Despite this, the p-values of the difference in means for these variables, which are reported in column (3), are greater than 0.05, indicating no statistically significant differences. This finding, despite the economically meaningful differences in the share of oil and mean fuel costs, reflects the presence of a great deal of heterogeneity among utilities within each group.

[23] We do not directly observe fuel receipts for 60% of power plants in deregulated states and 17% in regulated states.

Table 1: Characteristics of Deregulated, Control, and Matched Control Utilities in 1994

	(1)	(2)	(3)	(4)	(5)
	Deregulated	Control		Matched Controls	
	Mean	Mean	p-value of Difference from (1)	Mean	p-value of Difference from (1)
ln(MWh Retail)	15.21	15.22	0.977	15.40	0.717
ln(MWh Generated)	14.70	14.60	0.857	14.59	0.891
Marginal Generation Share: Coal	0.50	0.54	0.705	0.53	0.817
Marginal Generation Share: Gas	0.12	0.15	0.639	0.12	0.943
Marginal Generation Share: Nuclear	0.02	0.02	0.763	0.01	0.575
Marginal Generation Share: Oil	0.19	0.07	0.078	0.16	0.735
Marginal Generation Share: Water	0.18	0.20	0.763	0.18	0.960
Marginal Fuel Costs	65.69	37.89	0.137	59.11	0.795
Retail Price	78.76	58.95	0.001	59.78	0.002
Number of Unique Utilities	78	76		72	

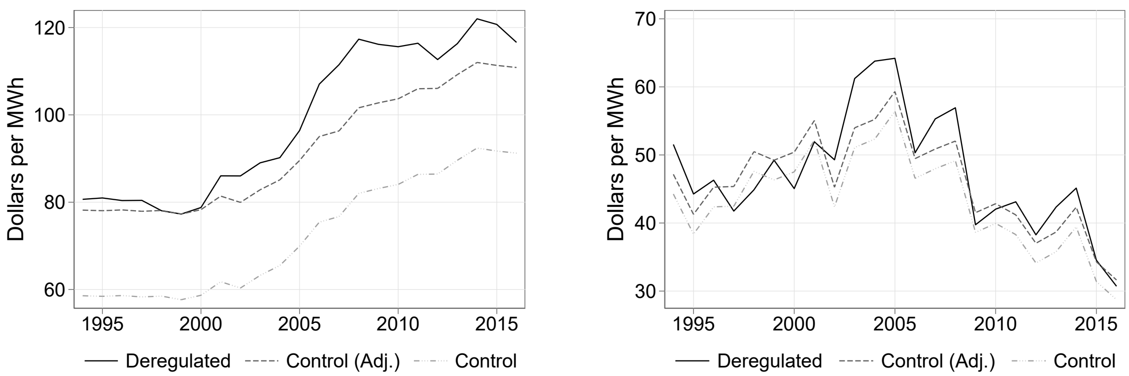
Notes: Table displays 1994 characteristics for 78 investor-owned utilities in states that later deregulated and 76 investor-owned utilities in states that did not deregulate. Columns (1) and (2) report the mean characteristics for each group, and column (3) reports the p-value of the difference in means. Column (4) reports the means for matched controls using a nearest-neighbor methodology, and column (5) reports the p-value of the difference in means between matched controls and the deregulated utilities. The first eight variables: (log) retail MWh, (log) generation MWh, marginal generation share by fuel type, and marginal fuel costs are used as matching variables.

Both of these features: mean differences across groups and heterogeneity within groups motivate our use of a matching procedure. By matching each deregulated utility to a set of similar controls, we can account for some of the heterogeneity in utility types. Specifically, we match utilities to three nearest neighbors based on 1994 values of (log) retail MWh, (log) generation MWh, marginal costs, and generation mix. Thus, we obtain a utility-specific control group that reflects both the type of generation and the size of the utility. We draw nearest neighbors from the pool of 76 control utilities. We provide additional details of our matching procedure in Section 4.2.

Column (4) in Table 1 reports the means for the nearest-neighbor controls, which are weighted by the number of times each utility is selected. Overall, the group becomes more similar to the deregulated utilities in terms of generation mix and fuel costs. For example, the difference in the oil share shrinks from 0.12 to 0.03. Marginal fuel costs for the matched control group increase to 59.5 dollars per MWh, which is close to the mean of 65.7 in the deregulated group. Correspondingly, the p-values for the matching variables tend to increase. The average p-value for the matching variables increases from 0.615 in column (3) to 0.787 in column (5). Note that the matching procedure only selects 72 out of the 76 possible control utilities as nearest neighbors.

Overall, utilities in deregulated states had higher prices than similar utilities in control states (79 versus 59 dollars per MWh). In 1994, implied gross markups are a small fraction of the

Figure 2: Aggregate Measures of Electricity Prices and Generation Costs



(a) Retail Prices

(b) Marginal Fuel Costs

Notes: Panel (a) plots the quantity-weighted default retail price for investor-owned utilities in deregulated states (solid line) and in control states (dotted light grey line). Panel (b) plots the average fuel costs of generation for all generating facilities that in 1994 belonged to utilities in deregulated states (solid black line) and control states (dotted line). The dashed line in both panels plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

retail price. Thus, our measure of fuel costs can explain much of differences in prices across the two groups. In addition, the difference in prices between the two groups was stable before the onset of deregulation. In Figure 2, we present the time series of average prices for both groups, where we weight the average by retail MWh in each service territory. Panel (a) shows the mean retail price for deregulated states with a solid line and the mean for control states, after adjusting for level differences in 1999, with a dashed line. From 1994 to 1997, prices were stable in both groups. From 1998 to 2000, prices in deregulated states fell slightly, while prices in control states remained flat. Starting in 2001, prices in both states began to rise. Deregulated prices outpaced control prices until 2005, when the gap between the two widened further.

Likewise, panel (b) of Figure 2 shows marginal fuel costs for the two groups. As described above, we calculate the marginal costs based on the 75th through 100th percentiles of fuel cost for the generators that utilities in each group owned in 1994. After accounting for level differences, fuel costs for generation facilities in deregulated markets closely tracked fuel costs in control markets from 1994 through 2004. Starting in 2005, generation costs began to decline, and they declined more rapidly in deregulated markets. This pattern can largely be explained by the greater use of natural gas generators in deregulated states, as the price of natural gas fell significantly with the expansion of fracking.[24]

The general patterns we observe are not sensitive to the particular measure of costs. In

[24]Using only generators that appear in at least 20 years of our sample (three-fourths of the 1994 generation facilities), the time series of marginal fuel costs are almost identical, indicating that lower average costs in deregulated states were not driven by the retirement of expensive generation facilities.

Figure A4 of the Appendix, we show similar trends using average variable costs rather than our proxy for marginal costs. In Figure A5 of the Appendix, we present trends costs using statewide measures of marginal and average variable costs, rather than utility-specific measures. As in panel (b) of Figure 2, we find declining costs in both deregulated and control states in the latter half of our sample.

Thus, though retail prices rose substantially in deregulated states, there was no corresponding rise in fuel costs in these states. Using our localized measure of generation costs, we find that fuel costs in deregulated markets declined overall. This high-level finding is consistent with an increase in markups in deregulated states relative to control states, and motivates our more in-depth empirical analysis in Section 4.

4 Measuring the Effects of Deregulation

4.1 Empirical Strategy

The goal of our analysis is to evaluate the effect of electricity restructuring on markups and prices. For this, we compare utilities in restructured states to those that remained vertically integrated and regulated, and we examine the evolution of costs, wholesale prices, and retail prices over time. Specifically, we use a difference-in-differences matching approach, which we describe in greater detail in the next section.

By individually matching utilities based on their size and fuel costs prior to the onset of deregulation, we are able to nonparametrically control for changes in macroeconomic factors—such as fuel costs and demand for electricity—when measuring a number of outcome variables. Matching on fuel costs also allows us to control some relevant geographical variation, since plants in different locations may face different fuel costs.[25] Intuitively, we are using the data to provide an answer to the question, "What happened for similar utilities in states that did not deregulate?"

Because a state decision to restructure its electricity sector was not completely random, causal inference in this context is difficult.[26] A causal interpretation of our findings would require the assumption of parallel trends, which has several nuances in our context. First, it requires that there were no ongoing trends that differentiated the two groups outside of deregulation. Though comparable utilities in states that implemented deregulation measures initially had higher retail prices (Table 1), markups were similar, and costs and prices follow similar trends from 1994 through 1999 (Figure 2). This suggests that the parallel trends assumption

[25]For robustness, we include a specification where we also include whether or not the utilities are in the same geographic area (Census region) in the matching procedure. This does change the set of matched utilities but has little impact on our results. We report this alternative specification in Tables A5 and A6 in the Appendix.

[26]This is highlighted by how little we know about the consequences of restructuring 20 years later (Bushnell et al., 2017), in spite of the sector's importance and the urgency of market rules that can aid the transition to decarbonization.

may be reasonable before the onset of restructuring.

Second, the parallel trends assumption requires that shocks unrelated to deregulation did not differentially affect deregulated and control states after implementation. The primary concern on this front arises from changes in fuel costs and environmental regulation, which we control for using our matching approach since the effect of these shocks depends primarily on the fuel mix.

Third, the assumption requires that the effects of deregulation did not spill over into control states. Because of the ongoing integration of electricity markets across states, it is indeed plausible that deregulation could have affected retail prices in neighboring states. However, if we account for spillovers, the data suggest that our findings may be a conservative *lower bound* of the effects of deregulation, as we also observe large increases in retail prices and markups in control states (Figure 2).

A final consideration is whether other aspects of markets that affected market power and cost efficiency developed differently following deregulation. For example, we expect entry decisions to follow different dynamics in restructured and vertically integrated states. We do not want to control for all of these factors, as some endogenous responses are part of the effect we want to estimate. Keeping this distinction in mind, we examine alternative mechanisms that could potentially affect our findings in Section 7. Though we find some differences in policies affecting deregulated and control states, these differences do not provide a consistent alternative explanation for the changes in prices and markups we observe. Thus, despite the above caveats, we believe our empirical results provide a compelling narrative that suggest the widespread presence and practice of market power.

4.2 Difference-in-Differences Matching Estimator

To measure changes in outcomes for deregulated utilities, we match utilities in states that implemented market-based prices (the "deregulated" group) to utilities in states that did not (the "control" group) based on pre-deregulation retail MWh, generation MWh, and fuel costs, using our measure of marginal costs. We then apply a difference-in-differences adjustment to the bias-corrected matching estimator developed by Abadie and Imbens (2006, 2011). Our estimation procedure closely follows the approach of Deryugina et al. (2019). Though we use the term "control" and "counterfactual," it is important to note that the state-specific decision to deregulate was not purely random, as discussed in the previous section.

For each of our 78 deregulated utilities, we use 1994 outcomes to identify the three nearest neighbors from the pool of 76 control utilities in our sample. By matching based on 1994 values, we can observe how outcomes evolve prior to deregulation and assess the plausibility of the parallel trends assumption. We use match on log generation MWh, log retail MWh, marginal costs,[27] and the shares of (marginal) generated MWh coming from five fuel types:

[27]When matching, we transform marginal costs using the inverse hyperbolic sine, $f(z) = \ln\left(z + \sqrt{1+z^2}\right)$, which

coal, natural gas, oil, nuclear, and water. We use a least-squares metric to calculate distances between utilities, with equal weights across the three variables. We scale up the fuel type distance measures so that, across all potential matched pairs, roughly equal weight is put on fuel types as the combination of the other three variables.[28] We use this distance to select the three nearest neighbors for each deregulated utility, allowing control utilities to be matched to multiple deregulated utilities.

We use these nearest neighbors to construct counterfactual outcomes and employ standard difference-in-differences techniques to adjust for pre-period differences. Let Y_{it} denote an outcome of interest (e.g., retail prices) for utility i in period t, where $t = 0$ corresponds to the year deregulation measures are implemented. Let $Y_{it}(1)$ indicate the outcome with deregulation and $\widehat{Y}_{it}(0)$ indicate estimated counterfactual without deregulation. Given $Y_{it}(1)$ and $\widehat{Y}_{it}(0)$, we can obtain a utility-specific estimate of the effect of deregulation on the outcome, $\widehat{\Delta Y}_{it}$:

$$\widehat{\Delta Y}_{it} = Y_{it}(1) - \widehat{Y}_{it}(0). \tag{1}$$

We observe the outcome $Y_{it}(1)$ for the deregulated utilities in our data. The counterfactual outcome, $\widehat{Y}_{it}(0)$, is unobserved and is calculated as follows. For each deregulated utility i, we select three nearest neighbors using the above procedure. We calculate the counterfactual outcome, $\widehat{Y}_{it}(0)$, as the average value of $Y_{it}(0)$ across the three matched control utilities plus the difference between deregulated and matched control outcomes in the period prior to deregulation. Thus, outcomes are indexed so that $Y_{i0}(1) = \widehat{Y}_{i0}(0)$. By indexing the levels to a baseline period, we obtain a utility-specific "difference-in-differences" estimate for any outcome of interest.

To quantify the average impact of deregulation across our utilities, we take the weighted average of the utility-specific treatment effects:

$$\widehat{\widehat{\tau}}_t = \frac{\sum_i \omega_i \widehat{\tau}_{it}}{\sum_i \omega_i}. \tag{2}$$

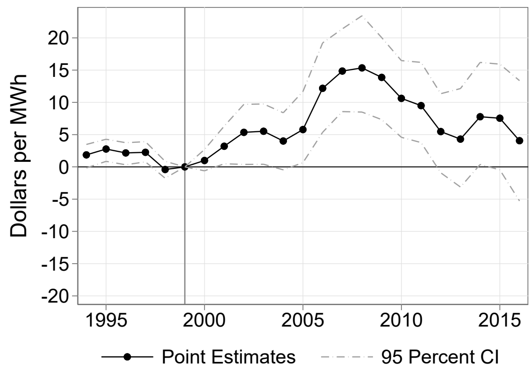
where ω_i is the retail MWh provided by the deregulated utility in 1994. Our weighting variable is chosen to capture the size of the utility with respect to consumption in its service area.

For our main analysis, we use 1999 as our baseline period across all states. Though there is some variation in terms of when deregulation measures legally came into effect across states, in practice, the restructuring effects all happened within a few years. This timing has little impact on the results we measure, which occur over 15 years after deregulation. Using a common baseline period has the advantage of making the empirical results more transparent, especially

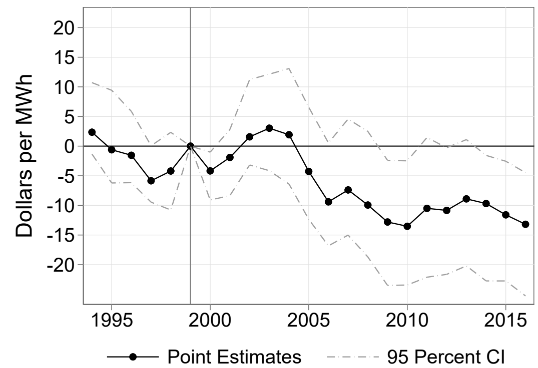
is approximately the natural log function plus 0.7 for $z > 5$ and also has $f(0) = 0$.

[28]Specifically, we scale up the shares by $\sqrt{30}$, though we obtain similar point estimates with alternative scaling factors (i.e., 1 or $\sqrt{300}$). The procedure yields reasonable nearest-neighbor matches for individual utilities. For the matched pairs, the chosen weight prioritizes the fuel mix. We match over three-quarters of the utilities almost exactly based on fuel types.

Figure 3: Estimates of Changes in Prices and Costs After Deregulation



(a) Retail Prices



(b) Marginal Costs

Notes: Figure displays difference-in-differences matching estimates of changes in (a) retail prices and (b) fuel costs for deregulated utilities. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to 1999, which is the year prior to the first substantial deregulation measures. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

for concerns about macroeconomic trends, such as changes in fuel prices. Our results are similar if we instead index treatment communities to their legal deregulation date.[29]

As in Deryugina et al. (2019), we employ a subsampling procedure to construct confidence intervals for our matching estimates.[30] Consider a parameter of interest, $\widehat{\theta}$. For each of $N_b = 500$ subsamples, we select without replacement $B_1 = R \cdot \sqrt{N_1}$ deregulated utilities and $B_0 = R \cdot \frac{N_0}{\sqrt{N_1}}$ control utilities, where R is a tuning parameter, N_1 is the number of deregulated utilities, and N_0 is the number of control utilities. For each subsample, we calculate $\widehat{\theta}_b$. The matching estimator converges at rate $\sqrt{N_1}$ (Abadie and Imbens, 2006, 2011), and the estimated CDF of $\widehat{\theta}$ is given by:

$$\widehat{F}(x) = \frac{1}{N_b} \sum_{b=1}^{N_b} \mathbf{1} \left\{ \frac{\sqrt{B_1}}{\sqrt{N_1}} \left(\widehat{\theta}_b - \widehat{\theta} \right) + \widehat{\theta} < x \right\} \tag{3}$$

The lower and upper bounds of the confidence intervals can then be estimated as $\widehat{F}^{-1}(0.025)$ and $\widehat{F}^{-1}(0.975)$. We employ $R = 3$ ($B_1 = 26$) for the confidence intervals and standard errors reported in the paper.

4.3 Prices, Costs, and Markups

We first show that retail electricity prices increased for customers in deregulated states. Panel (a) of Figure 3 displays the average change in retail prices relative to matched controls. Leading up to the baseline year of 1999, there is little difference in price trends for deregulated and control utilities. From 2000 to 2005, deregulated utilities saw modest increases in retail prices, which an average difference of 3.9 dollars per MWh over that period. In 2006, deregulated utilities realized a sharp rise in retail prices, with an average difference of 12.6 dollars per MWh from 2006 to 2011 and an overall increase of 7.9 dollars per MWh from 2000 to 2016. The increases in the latter years are large in magnitude. The average retail price for deregulated utilities in 1999 was 78.0 dollars per MWh, so an increase of 12.6 dollars per MWh corresponds to a 16 percent increase in prices relative to the baseline. We reiterate that these changes are difference-in-differences effects, i.e., increases above and beyond the price trends occurring in control utilities.

A natural question is whether the price changes reflect underlying changes in costs. Panel (b) of Figure 3 plots the relative marginal generation costs for deregulated utilities. Relative to control utilities, deregulated utilities saw a *decrease* in generation costs in the post-deregulation period. From 2000 to 2016, fuel costs declined by 6.9 dollars per MWh in the deregulated utilities. Thus, despite declining costs, prices rose in deregulated states.

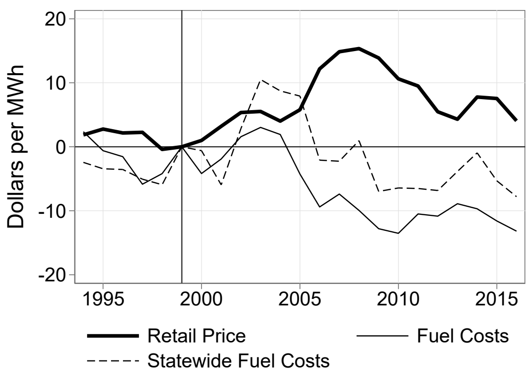
The combined effects of increasing prices and decreasing costs suggest that markups to consumers rose in deregulated states. To illustrate this, we combine the retail price effects and the generation costs on the same plot in panel (a) of Figure 4. The difference between the retail price (in thick solid black) and the fuel costs (in thin solid black) is the gross markups paid by end consumers above the generation costs of electricity. The gross markups are plotted in panel (b). The increase in gross markups was modest from 2000 until 2005. Markups spiked in 2006, with an increase of over 20 dollars per MWh from 2006 through 2011.

Our finding of increasing markups is robust to our measure of costs. As an alternative measure to the utility-specific generation costs, we calculate marginal costs from all utility and independent power producer generators within the same state. An argument for using this measure as opposed to the utility-specific measure is that, in a competitive market, consumers may obtain electricity from a lower-cost source that is nearby but outside of their service area. Additionally, this alternative measure accounts for entry of new plants. The dashed line in panel (a) plots the change in statewide fuel costs. Though the decline is not as quite large as the utility-specific measure, we find that statewide fuel costs decline in deregulated utilities relative to their controls. The dashed line in panel (b) plots the gross markup for retail prices using this alternative measure of costs. We still find large increases in gross markups to consumers using

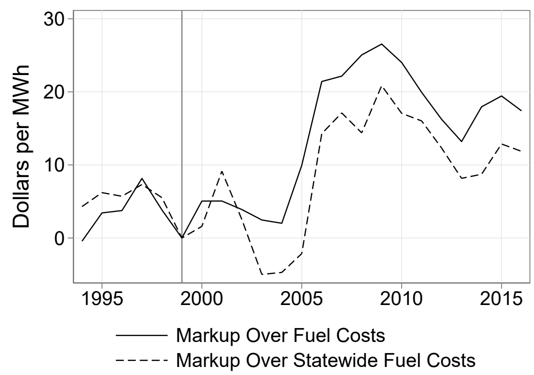
[29] For a comparison, see Figures A2 and A3 in the Appendix.

[30] Matching estimators do not meet the regularity conditions required for bootstrapping (Abadie and Imbens, 2008), and subsampling provides great flexibility in terms of calculating treatment effects.

Figure 4: Prices, Costs, and Gross Markups



(a) Prices and Costs



(b) Gross Markups

Notes: Figure displays difference-in-differences matching estimates of changes in prices, costs, and gross markups for deregulated utilities. Panel (a) provides the point estimates for retail prices (thick line) and utility-specific fuel costs (thin solid line) from Figure 2 on the same plot. The dashed line on the plot represents an alternative measure of costs reflecting the average statewide fuel costs for all generators in each utility's state. Panel (b) displays the changes in the gross markups, which are defined as the retail price minus fuel costs, using both measures of costs from panel (a).

this alternative measure.

Table 2 summarizes the estimated difference-in-differences coefficients, as well as the baseline measures, for our key outcomes of interest.[31] The overall changes in retail prices and gross markups from 2000-2016 are large and highly significant. The changes in generation costs and wholesale markups we observe are economically meaningful and statistically significant at the 0.10 level. We find stronger effects for prices and generation costs starting around 2006. As discussed earlier, our findings are similar if we index each utility to state-specific implementation dates, rather than calendar time. Figure A2 in the Appendix shows that the share of own generation divested looks nearly identical using both measures of time. Appendix Figure A3 plots the corresponding effects on prices and costs, which are similar to the estimates in Figure 3 above.

As a robustness check, we estimate an alternative version of our matching procedure where we also weigh whether or not the control utility is in the same geographic area. For this procedure, we use Census regions (Northeast, Midwest, South, and West), and we choose a scaling factor that meaningfully changes the mix of matched control utilities. This has little impact on our results. We report the summary stats and outcomes with this specification in Tables A5 and A6 of the Appendix.

[31]The changes in markups in Table 2 do not always equal difference in changes between prices and costs because there are some periods where we do not observe wholesale prices for some utilities. In these cases, we do not calculate retail or wholesale markups.

Table 2: Relative Changes in Prices, Costs, and Markups

	(1) Retail Price	(2) Wholesale Price	(3) Generation Cost	(4) Retail Markup	(5) Wholesale Markup	(6) Gross Markup
1999 Values	78.06	42.81	48.89	34.95	−5.22	29.13
2000-2005	4.14	−0.42	−0.63	4.87	−0.26	4.74
	(1.74)	(2.97)	(2.88)	(2.45)	(4.52)	(3.59)
2006-2011	12.73	3.46	−10.59	9.38	12.30	23.18
	(2.95)	(3.49)	(4.82)	(3.84)	(6.03)	(5.72)
2012-2016	5.83	7.41	−10.83	2.63	16.40	16.80
	(3.83)	(4.18)	(4.92)	(4.10)	(6.56)	(6.01)
2000-2016	7.66	3.16	−7.11	5.62	8.82	14.71
	(2.30)	(2.99)	(3.59)	(2.73)	(4.68)	(4.40)

Notes: Table displays the estimated difference-in-differences matching cofficients for prices, costs, and markups between deregulated and control utilities in dollars per MWh. The first row provides the baseline values in 1999, and the remaining rows provide the average effect for the specified time period. Standard errors are displayed in parentheses.

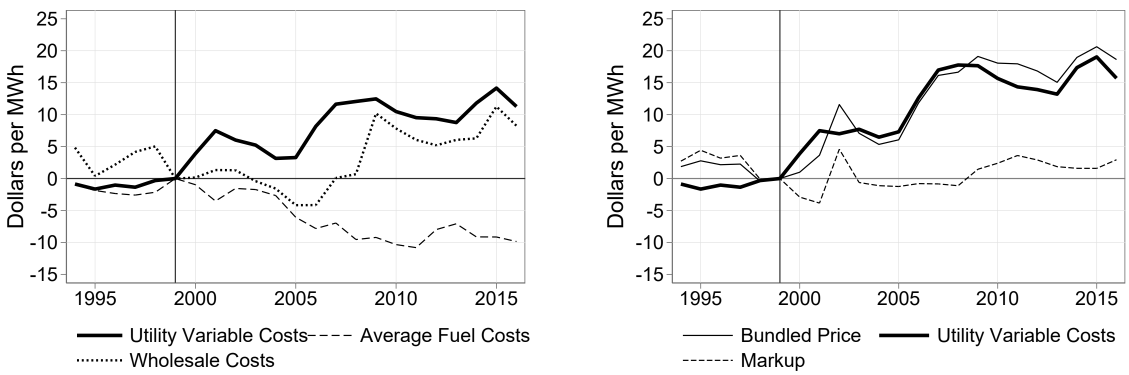
Section C in the Appendix discusses the variation in these effects across states. We estimate some heterogeneity across states. Most deregulated states realized meaningful price increases, with 9 states realizing price effects exceeding 5 percent. We estimate that consumers in some states did benefit from deregulation, with consumers in Virginia and Illinois realizing meaningful decreases in prices.

4.4 Where is the Increase in Markups Coming From?

Our above findings indicate an increase in gross markups paid by end consumers and higher prices. To unpack these changes, we now focus on incumbent utilities. In most states, even after deregulation, these utilities were required to continue to offer “bundled” service—i.e., providing retail electric service in addition to distribution—at regulated prices based on the procurement costs of electricity. At the same time, the utilities were required to switch from own generation to wholesale market purchases to supply these consumers. By studying how costs and prices moved for incumbent utilities, we illustrate the important role of generation markets and the underlying mechanisms that explain the estimated price changes.

Panel (a) of Figure 5 shows the impact of deregulation on the procurement costs for utilities using our difference-in-difference matching approach. The average variable costs for utilities (thick black line) increased shortly after the divestiture of generation facilities in 2000, and it remained 5 to 15 dollars per MWh higher throughout the sample period. The variable cost of electricity is the weighted average of the average fuel cost for generation by the utility (thin dashed line) and the average cost of electricity purchased from wholesale markets (dotted line).

Figure 5: Utility Costs and Markups



(a) Utility Variable Costs

(b) Utility Prices, Costs, and Markups

Notes: Figure displays difference-in-differences matching estimates of changes in costs, prices, and markups for regulated electric service in deregulated states. The thick black line in both panels shows the change in average variable costs for utilities. Each utility's average variable cost is calculated as the weighted average of generation fuel costs and wholesale purchase prices. Changes in these variables are shown in panel (a). Variable costs increase from 2000 through 2005 despite no increase in generation fuel costs (dashed line) and wholesale purchase prices (dotted line) because utilities procured a greater fraction of electricity from wholesale markets. Panel (b) plots the regulated bundled price (think solid line) and the utility markup (dashed line), defined as the bundled price minus the average variable cost.

Two factors contribute to the increase in average variable costs. The first is that, by separating from generation facilities, deregulated utilities had to procure a greater portion of the electricity sources from the wholesale market. For a utility, obtaining electricity from the wholesale market was more expensive than generation, as wholesale prices reflect a markup. In 1999, the mean wholesale markup over average variable generation costs was 17.1 dollars per MWh. Thus, despite the fact that wholesale prices and fuel costs both *declined* over the period 2000 to 2005, utility variable costs *increased* by 5.6 dollars per MWh. With deregulation, utilities effectively paid a market-based markup to generation facilities that they had previously owned.

The second factor that led to an increase in average variable costs for utilities was the increase in wholesale prices beginning in 2007. Though wholesale prices remained relatively flat in the initial years of deregulation, they eventually increased substantially, rising by 8 dollars per MWh from 2012 to 2016. The increase in wholesale prices, combined with the significant declines in fuel costs, indicate that wholesale markups for generators increased substantially in deregulated states. Our difference-in-differences estimate for the increase in wholesale markups is 8.9 dollars per MWh from 2000 to 2016, which is over 60 percent of the overall increase in gross markups.

For bundled service, incumbent utilities were required to charge prices equal to the variable costs for electricity. We should expect then, that, ceteris paribus, utility variable costs should move one-for-one with prices for bundled electric service. Indeed, panel (b) of Figure 5 shows that the increase in utilities' average variable costs (thick solid line) fully explains the increase in regulated bundled prices (thin solid line). In other words, the increase in retail prices we observe did not arise from an increase in utility "markups"—i.e., additional charges to cover higher distribution costs, stranded costs payments, or other features. Utility markups moved similarly in deregulated and control states, as shown by the dashed line in the figure.

The changes documented in Figure 5 point to the role of two fundamental economic mechanisms in explaining price increases in deregulated states. First, the divestiture of generation facilities allowed for double marginalization, as generators were able to charge markups to downstream utilities. This mechanism corresponds with the price increases we observe before 2005, where utility variable costs increased despite declines in wholesale prices and fuel costs. Average generation markups did not increase, but markups were applied to a much larger share of generated electricity. Over this period, retail markups for incumbent utilities remained constant, though there were modest retail markups for alternative retail suppliers.

The second mechanism was an increase in the exercise of market power by generators, which corresponds to the rise of wholesale prices after 2005. Prior to this year, generators in many states were not able to raise prices due to the presence of long-term contracts and rate caps at the retail level. In Section 6, we examine the timing of this change in more detail.

Although some have viewed market power in wholesale electricity markets as a factor only during a few hours of peak demand, our findings indicate that market power is more pervasive than that. At an annual level, we find substantial markup increases even over the costs of the most expensive power plants, which typically determine prices on an hour-by-hour basis. Moreover, our data suggest that generators are signing longer-term (annual or longer) contracts at a markup over generation costs. We observe similar price increases in ISO markets and contract markets, as shown in Figure A7 in the Appendix.

5 Market Power in Wholesale Electricity Markets

In this section, we present evidence supporting the presence of market power in wholesale electricity markets. We first look at how concentration of buyers and sellers has evolved in wholesale markets. Deregulation did not substantially change seller concentration, and there was a notable lack of entry. Buyer concentration fell, potentially decreasing buyers' bargaining power and contributing to higher wholesale prices. Second, we show that there is correlation between measures of potential competition—i.e., features of market structure at the time of deregulation—and the change in wholesale markups. Third, we show that changes in prices are not positively correlated with changes in fuel costs. In fact, states with higher fuel costs realized greater declines in costs yet relatively higher prices. Fourth, we show that utilities with a more elastic demand, as measured by a higher share of industrial consumers, saw a higher increase in markups. Finally, section 5.4 shows that the effects on rates for incumbent utilities did not significantly vary by customer type, despite different elasticities. These findings are consistent with market power being exercised at the wholesale level.

We run these analyses at the state level. While ISO markets have integrated markets across utility serving areas, creating, in some cases, larger market areas, we think it is reasonable to use historical regions due to the cost of transmission and because entry has been limited. Taken as a whole, these pieces of evidence support our earlier finding of generator market power as the main driver of price increases after deregulation.

5.1 Upstream and Downstream Concentration

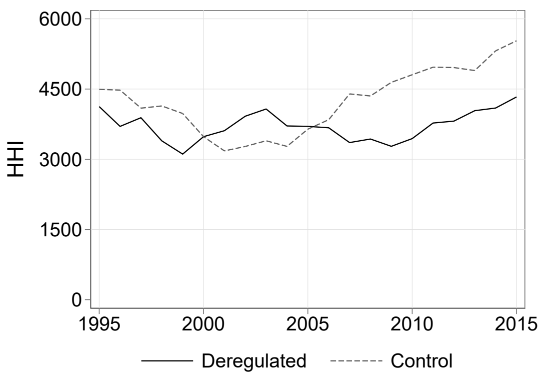
In this section, we use our detailed data, which provides a complete map of the corporate structure of the electricity industry, to accurately measure concentration at the wholesale and retail level over time.[32] Our findings indicate that concentration among wholesale sellers has remained high over the last two decades despite significant changes in market structure. Concentration among wholesale buyers has decreased over time, as expected with the introduction of retail competition, though it has remained high. While concentration is not necessarily an accurate measure of market power, these findings suggest that buyers have lost market power relative to sellers, which contributes to explain why utilities had to agree to higher prices when they sign contracts with new providers after their existing contracts expired.

We evaluate changes in concentration in upstream and downstream markets by calculating the Herfindahl-Hirschman Index (HHI) for restructured and control states. We find that concentration remained high in the upstream market for sellers. Though utilities were forced to divest their generation assets, this did not result in a substantial reduction in concentration. Often, a utility's entire generation portfolio was transferred to a single new entity, resulting in minimal changes to local competition. In the downstream market, we find that concentration decreased. Both forces—high concentration upstream and lower concentration downstream—could have increased wholesale prices (and markups) in restructured states. Decreasing concentration, or increased competition, in the retail market could increase wholesale prices through a reduction in buyer power. Initially, utilities were by far the largest buyers in their local markets. After vertical separation, utilities could purchase from several generation owners, some of which were affiliated companies. Over time, as retail competition increased, utilities' market share in the downstream market declined (see Figure 13 in Section 6). We think this change in the relative balance of bilateral market power may have contributed to the increase in markups in restructured states.

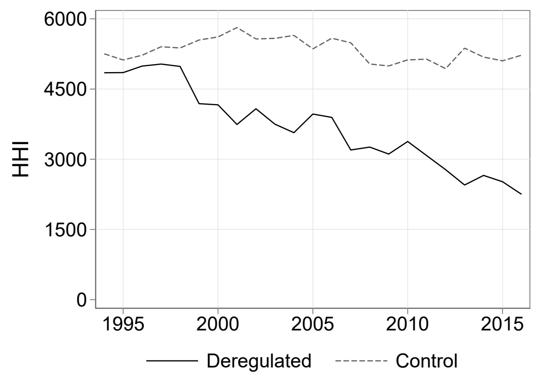
Panel (a) of Figure 6 shows the evolution of the mean HHI among firms that sell electricity to investor-owned utilities, as reported in FERC Form 1. Sellers have been aggregated to the

[32] We track ownership up until the ultimate parent company level.

Figure 6: Concentration Upstream and Downstream by Restructured Status



(a) Seller HHI



(b) Buyer HHI

Notes: The figure shows the evolution of the mean HHI over time, where the HHI is computed at the state level for both buyers and sellers. Buyers include investor-owned utilities and power marketers, as reported in EIA data. Sellers include all firms that sell to an investor-owned utility, as reported in FERC Form 1 data. For sellers, concentration is calculated at the parent company level.

parent company level, such that if a utility reports purchasing from a certain power plant, and the plant is owned by Exelon, for example, we consider that transaction as a purchase from Exelon. Both deregulated and control states were highly concentrated at the beginning of our sample and remained so, with average HHI levels consistently above 3,000.[33] Despite shifting an increasing share of energy to wholesale markets and encouraging independent generation, seller concentration did not decrease.[34]

Panel (b) of Figure 6 shows the evolution of the mean HHI among buyers for restructured and regulated states, where buyers include both investor-owned utilities and power marketers. Concentration remained roughly constant between 1995 and 2015 in regulated states. In restructured states, on the other hand, concentration started falling in the late 1990s, when the restructuring process started, and continued to do so through 2016. This pattern mirrors the increase in competition we observe in the retail sector. By the end of our sample, buyer HHI had crossed from the highly concentrated to the moderately concentrated range.

In summary, Figure 6 indicates that concentration among buyers decreased in restructured states, while seller concentration remained constant. This is consistent with sellers maintaining a high degree of market power and provides an explanation for the large markups we observe when prices are deregulated. In particular, we would expect buyers bargaining power to have decreased around 2005 when they had to sign new procurement contracts after the existing

[33]The US Department of Justice considers an HHI above 2,500 to be "highly concentrated," and an HHI between 1,500 and 2,500 to be "moderately concentrated."

[34]Regulated utilities generate most of their energy, so concentration measures for sellers in regulated states describe very small markets. After restructuring occurs in deregulated states, concentration measures are more representative because a much larger share of the market is traded.

ones expired. This correlation is not necessarily causal because market concentration is endogenous, but it is consistent with market power as the main explanation for our findings.

The above findings suggest that the entry of new generation plants did not not substantially affect upstream market concentration after deregulation. In a competitive market with free entry, we would expect high markups to attract new entrants, so we examine the entry of new generators over time. Persistently high markups are only possible if there are significant entry barriers, since otherwise new firms would enter the market to capture these high profits. Figure 7 shows the evolution of new capacity in the United States over time as a fraction of total capacity, net of retiring capacity. The figure shows an entry boom in the early 2000s, a period of optimism boosted by high capital availability and low gas prices (Kwoka, 2008a). These high levels of investment were rather an exception, since for most years entry of new capacity is relatively low (below 3 percent) for both deregulated and control states, though slightly lower in deregulated states.

Kwoka (2008a) documents the paucity of investment and lists several reasons, including large investment costs for new generators (e.g., $225 million for a gas generator of efficient size), long lead times for construction, the need for new transmission connections, the fact that incumbents already have plants in the best locations,[35] and time lags for regulatory approval ranging from 8 to 14 months. Further, unlike many other capital investments, investments in new generation plants are almost entirely sunk, as they plants cannot be repurposed for other uses. This, coupled with the long repayment period over decades, subjects any investor to a high degree of risk. In electricity markets, special risks include regulatory policy uncertainty, fuel cost uncertainty, environmental policy uncertainty, and technological uncertainty, all making investments in new generation more difficult.

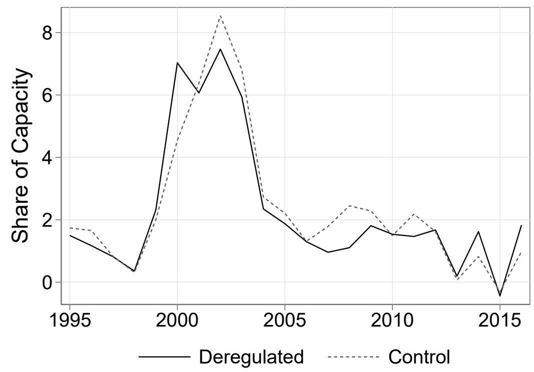
5.2 Supply-Side Factors

The previous section showed that upstream and downstream markets were highly concentrated and remained so after deregulation. Concentration levels, though suggestive, may not be a definitive indication for the presence of market power. In markets with homogeneous products, concentrated markets can still deliver close to marginal cost pricing when firms compete in prices, as in the classic Bertrand model.

To provide further evidence for the presence of market power, we examine heterogeneity across utilities. If electricity markets were characterized by near-perfect competition, then there would be no correlation between measures of market structure (such as concentration) and estimated changes to markups—any competition would be sufficient to drive prices down to marginal costs. On the other hand, if firms can exercise market power, then we might expect that variables correlated with competition will also correlate with changes in markups.

[35]Thermal plants need to be close to water and transmission. Renewable plants close to transmission and in an area with high wind or solar energy potential.

Figure 7: Net Entry of New Capacity



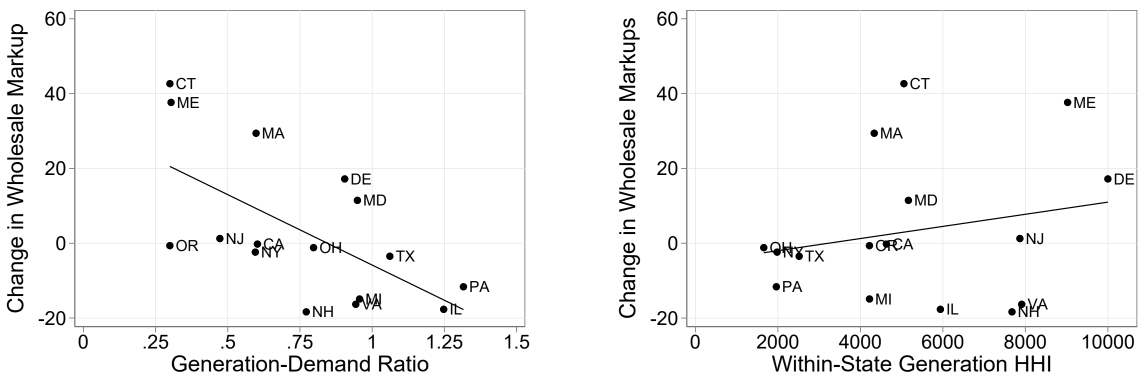
Notes: Figure displays the evolution of new nameplate capacity as a fraction of total capacity, net of retiring capacity, distinguishing between deregulated and regulated states. Only operating plants are included.

We consider two variables that would be expected to affect the intensity of competition in deregulated markets. We focus on upstream markets, as we estimate changes to be primarily driven by increases in wholesale markups. First, we consider a measure of potential *within-market* competition. For the pre-deregulation period, from 1994 to 1999, we calculate the average MWh generated and the average retail MWh demanded. We use the ratio of the two as a measure of the total potential within-market competition for generators. A lower value of this measure indicates that local generation is relatively scarce and imports of electricity from other service areas are more likely to be needed to cover demand. Since deregulation is state-specific, a higher value indicates that a greater share of production is subject to the effects of deregulation. If deregulation increases the role of competitive forces in the local market, then higher values should lead to less market power after deregulation. A ratio exceeding one indicates that local capacity exceeds demand, as the utility was a net exporter before deregulation.

Second, we consider a measure of *cross-market* competition. We exploit the fact that deregulated states varied in terms of the number of incumbent investor-owned utilities. In states with more utilities, after restructuring there are potentially more sellers to purchase electricity from in the newly created wholesale market. We capture the potential impact of competition from generators outside of the service area by measuring the within-state HHI of generation for each utility from 1994 to 1999. A lower concentration value would mean that the average buyer has more choices from the same state but outside the local service area after deregulation.

Figure 8 plots the impact on wholesale markups against our measures of competition. For this analysis, we measure costs and markups using our statewide measure of marginal costs. Impacts on markups are aggregated at the state level and across years 2000–2016, and the measures of competition are calculated relative to 1994–1999. We aggregate utilities to the state level, weighing each utility by retail MWh in 1994. We drop Rhode Island from our plots,

Figure 8: Potential Competition and Markups



(a) Within-Market Competition

(b) Cross-Market Competition

Notes: The figure shows the correlation between the estimated impact on wholesale markups, aggregated across years 2000-2016, and two measures of potential competition, aggregated across pre-deregulation years 1994-1999. Panel (a) presents correlation with generation-demand ratio, used as a measure of within-market potential for competition. Panel (b) presents correlation between estimated impact on wholesale markups and the within state generation HHI, interpreted as measure of cross-market potential for competition. We aggregate utilities to the state level, weighing each utility by retail MWh in 1994. We drop Rhode Island from our plots, as the generation plants for largest utility were very small and exited our sample after 1999, so we have no measure of wholesale markups for that utility.

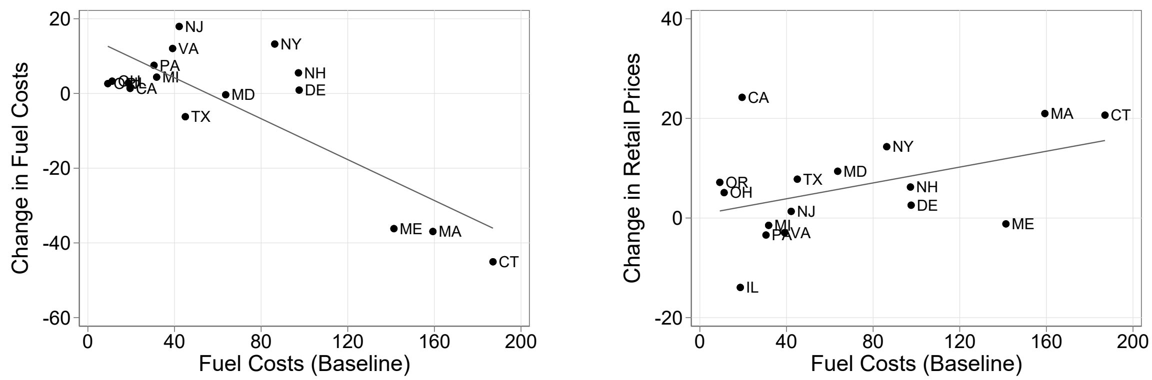
as the generation plants for largest utility were very small and exited our sample after 1999, so we have no measure of wholesale markups for that utility.

Panel (a) plots the change in wholesale markups versus the generation-demand ratio. Consistent with the presence of market power, lower potential within-market competition is associated with greater increases in wholesale markups. The correlation coefficient is -0.33. Panel (b) plots the change in wholesale markups against the within-state generation HHI. Consistent with the presence of market power, more concentrated markets have larger increases in wholesale markups. The correlation coefficient is 0.36.[36] These figures are in line with our explanation of increased markups in deregulated markets coming from market power.

To further investigate market power from the supply side, we analyze how the effects of restructuring varied across states according to pre-deregulation fuel costs. In a perfectly competitive market, we expect prices to be determined by marginal costs and therefore to move in proportion to costs. Therefore, states that see the largest declines in costs are expected to see commensurate effects on prices under competitive conditions. We examine whether this holds in Figure 9, which plots the relationship between pre-deregulation fuel costs, aggregated across pre-deregulation years 1994–1999, and impacts on both fuel costs and retail prices, aggregated across years 2000–2016. We aggregate utilities to the state level, weighing each utility by retail MWh in 1994. As before, we drop Rhode Island due the exit of its generation plants.

[36]The correlation coefficient for our two measures of potential competition is -0.20.

Figure 9: Changes in Fuel Costs and Prices Relative to Baseline Costs



(a) Fuel Costs

(b) Retail Prices

Notes: Panel (a) in the figure shows the correlation between pre-deregulation fuel costs and the estimated effect on fuel costs. Panel (b) shows the correlation between pre-deregulation fuel costs and the estimated effect on retail prices.

Panel (a) shows the correlation between pre-deregulation fuel costs and the estimated effect on fuel costs. States that had the highest costs initially saw the largest reductions, suggesting that inefficiencies explained the higher costs. The correlation coefficient is -0.78. Panel (b) plots pre-deregulation fuel costs against the estimated effect on prices. In a perfectly competitive world, both panels would look similar. By contrast, what we find is that states that had the highest pre-deregulation costs and highest cost declines also saw the largest price *increases*. The correlation coefficient between the average price impact and the baseline fuel costs is 0.49. The observation from these two figures is consistent with a market in which firms have market power, not a competitive one. Utilities might have been able to exert market power by inflating their costs in a regulated environment, and by charging higher markups in a deregulated market with market-based prices.

5.3 Elasticity of Demand

As an additional check to confirm that our findings are driven by firms' market power, we examine how the effects on markups vary with the elasticity of the demand. Although we do not directly estimate the elasticity of demand, we observe the share of industrial, commercial, and residential customers served by each utility, which is highly correlated to elasticity. Residential customers are typically less responsive to prices, while industrial customers have higher electricity bills and more flexibility over the timing of their consumption, which makes them more sensitive to prices (Fan and Hyndman, 2011; Burke and Abayasekara, 2018). In line with this categorization, retail competition has generally resulted in greater switching for industrial customers, while residential customers face significant switching and search costs and stay longer

Table 3: Markups and Demand Elasticity

	Gross Markup		Wholesale Markup	
	(1)	(2)	(3)	(4)
Share Residential 1994–1999	118.5***		146.9***	
	(32.83)		(40.20)	
Share Industrial 1994–1999		-87.39***		-122.0***
		(13.68)		(12.56)
Constant	-30.51**	37.74***	-49.87***	40.16***
	(14.84)	(11.88)	(17.01)	(8.123)
Year FE	Yes	Yes	Yes	Yes
Observations	733	733	603	603

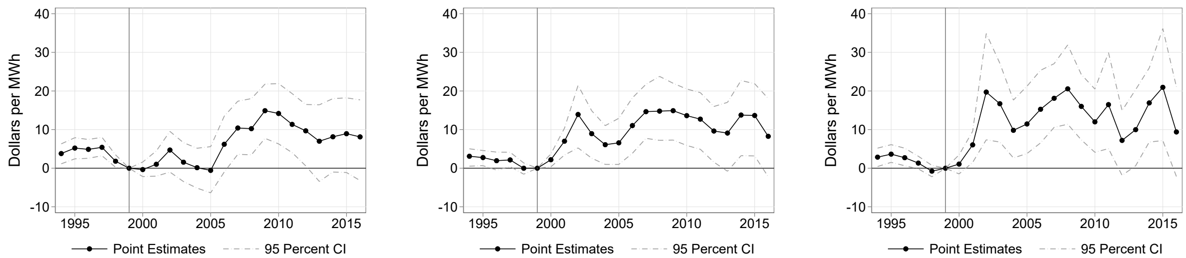
Notes: *** $p < 0.01$; ** $p < 0.05$; * $p < 0.1$. The dependent variable is the estimated effect on markups, which is regressed on the average share of residential and industrial customers from 1994 through 1999. Gross markup is retail price minus fuel cost. The sample contains observations at the utility level between 2006 and 2016. Coefficients are calculated using median regression with retail MWh sold in 1994 as weights.

with the incumbent provider (Hortaçsu et al., 2017). Importantly, the proportions of each group in a utility service area are arguably exogenous since for the majority of households and businesses electricity expenses are not significant enough to be a determinant factor in their location decisions. Consistent with this hypothesis, we find larger effects on markups for utilities that have a relatively higher share of residential customers or a lower share of industrial customers.

We examine the relationship between the estimated effect on markups and the share of residential or industrial customers in the area served by a given utility, which is strongly correlated with the elasticity of the demand faced by the utility. Table 3 presents results from regressing the estimated effect on markups on the share of residential or industrial customers in a utility's area, on average, from 1994 through 1999, using outcomes between 2006 and 2016. The sample is restricted to this period because this is when markups changed and we are interested in the mechanism behind this change. We use the shares from 1994 through 1999 because they are not affected by the prices charged by the utility in subsequent years. This provides a relatively clean proxy for the elasticity of the demand in that market. We analyze the relationship between markups and demand elasticity using both wholesale markups and gross markups, which are retail prices minus fuel costs, and find similar results for both measures. To mitigate the impact of outliers, we drop five utilities that do not have any residential customers, and we use median regressions.

Results in Table 3 indicate that utilities with a higher share of residential customers from 1994 to 1999, which is our proxy for more inelastic demand, had larger increases in markups. We also find that the share of industrial customers has a negative relationship with changes in markups, which would be expected when industrial customers exhibit more elastic demand.

Figure 10: Effects on Utility Rates by Customer Type



(a) Residential (b) Commercial (c) Industrial

Notes: Figure displays difference-in-differences matching estimates of changes in bundled service retail prices for deregulated utilities. These prices are determined by procurement costs for the utilities. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to 1999, which is the year prior to the first substantial deregulation measures. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

These findings are consistent with deregulated firms exerting market power, charging higher markups in markets with more residential consumers and less elastic demand.

5.4 Heterogeneity in Effects by Customer Type

To further investigate the potential role of market power, we examine the effects of deregulation on different types of customers. We consider the three primary classes of electricity customers: residential, commercial, and industrial. To isolate the effect arising from the upstream market, we focus on bundled service rates available from local utilities. Though deregulation allowed for market-based prices, utilities that continued to operate in these retail markets were required to offer prices based on average variable costs. In effect, these utilities offered a price equal to the cost of procurement from the wholesale market, plus additional fees to cover distribution costs.

Observing similar changes in these rates across different classes of customers would be consistent with the exercise of market power in the wholesale market. Upstream generation facilities have little ability to price discriminate across different types of customers when selling to a utility, which bundles demand across customer types. If we observed instead that, for example, residential customers saw much greater increases in prices, we might infer that greater market power is exercised in downstream markets, where retailers can easily distinguish among types of customers. Alternatively, differential changes by customer type may also indicate special fees or subsidies provided as a result of deregulation to specific types of customers.

Figure 10 plots the difference-in-difference matching estimates of changes in utility retail prices by customer type. Overall, we find similar effects across different types of customers. All three types observe statistically significant increases in prices, with an average effect between 10 and 15 dollars per MWh from 2009 through 2016. Consistent with cost-based regulation of these prices, these effects are very similar to the change in utility variable costs we report in panel (a) of Figure 5, which also average between 10 and 15 dollars per MWh over the same period. Overall, the fact that we observe similar increases in cost-based prices across customer types further suggests the important role upstream market power to increase prices in deregulated markets.[37]

One notable difference is that commercial and industrial customers realized price increases as early as 2001, whereas residential prices did not begin to increase until 2006. This is consistent with practice of implementing rate freezes along with deregulation, which fixed rates at pre-deregulation levels. Rate freezes were disproportionately targeted toward residential and small commercial customers. Thus, in many states, large commercial and industrial customers were immediately subject to the changes in variable costs realized by utilities in the aftermath of deregulation. We discuss the increase in utility variable costs and the rate freezes in more detail in Sections 4.3 and 6, respectively.

Consistent with our findings above, industrial and commercial customers are much more likely to switch away from the regulated utility rates. This transition was gradual, in contrast with the sudden increase in prices we observe.[38] See Figure A6 in the Appendix for estimated effects on the consumption of bundled service from the incumbent utility by customer type.

6 Delayed Effects of Deregulation

Price effects that result from deregulation may not be realized until many years after deregulation measures are enacted. Though many utilities were forced to legally separate from generation facilities abruptly, other measures were put in place that delayed actual changes to the structure of the market. For example, many utilities signed long-term procurement agreements with now independently operated generation facilities. These contracts effectively postponed the implementation of a competitive wholesale market, as much of the generation capacity was under long-term contracts. The possibility of delayed *effective deregulation* can explain why we observe larger price increases after some time.

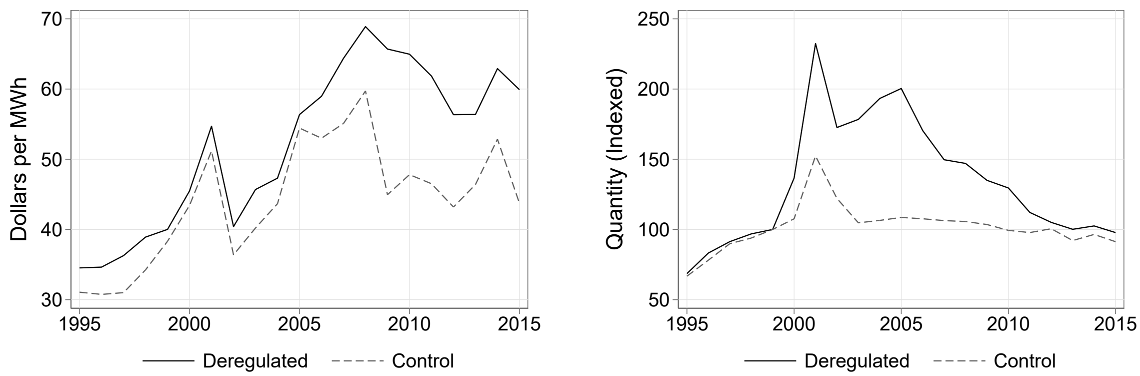
6.1 Long-Term Contracts

When deregulation measures were passed, most states imposed rate freezes or rate caps to guarantee low prices for consumers during the initial post-deregulation adjustment period. At the same time, utilities were vertically separated and signed long-term contracts with generators. The rates of these contracts were low because utilities were in good bargaining positions: there were no other significant buyers in the area and generators knew that their retail rates

[37]These results further suggest that the significant differences in markups across utilities shown in Table 3 are due to differential upstream behavior, as opposed to downstream price discrimination to different customer types.

[38]With the exception of Texas and Maine, which fully eliminated regulated rates for some utilities.

Figure 11: Contract Purchases



(a) Average Price: Largest Seller (b) Average Quantity: Largest Seller

Notes: Figure plots mean characteristics for the largest buyer-seller relationships for each utility. We identify the largest seller to each utility by looking at aggregate MWh transacted for each seller-utility pair in each year. Panel (a) of the figure displays the average price paid to the largest sellers, and panel (b) displays the average quantity sold for that buyer-seller relationship. Quantities are based on MWh and are indexed to 100 for 1999 values. Values are plotted separately for utilities in deregulated states (solid lines) and control states (dashed lines).

were capped, so utilities could not pay more without incurring in losses. This situation changed around 2005, when both rate caps and contracts expired.[39] Two changes decreased utilities' bargaining position. First, utilities could pay more since they were allowed to increase rates if costs increased. Second, generators could sell to other buyers besides the utility, since wholesale centralized markets were starting to pick up (see Figure 14) and retail electricity providers had gained some market share.[40]

We examine the use and expiration of large long-term contracts in our data. Although we do not observe the exact expiration date of procurement contracts, we have annual data on transactions by seller for every utility, which allows us to explore how contracts evolved. Figure 11 presents characteristics of the contracts with the largest seller for each utility each year, separately by deregulated and control states. In panel (a), we see that initially prices in both groups moved roughly together, with utilities in restructured states paying only slightly more for energy. After 2005, the two series diverge, increasing substantially more in restructured states. Panel (b) on the right shows how the quantities purchased from the largest seller have evolved. The values are indexed to 100 in 1999. There is an early spike after 2000, when utilities purchased more energy after divesting a significant share of their power plants. The

[39]See the discussion of the case of Illinois in Section 6.2 for an illustration. Several states had similar timelines. For example, Maryland's rate freezes and rate caps began to expire in 2004, Delaware's price cap expired in 2006, Massachussetts' in 2004, Connecticut mandated a 10% reduction below 1996 rates for the period 2000-2003, and Virginia had price caps for the first six years after deregulation (expiring in 2006). All these states saw wholesale prices increasing around 2005.

[40]Section 5.1 shows how seller concentration remained fairly constant in the wholesale market during the last two decades, while buyer concentration decreased as retail competition became stronger.

purchases from the largest seller remain high until 2005, where the largest contract is twice as large as it was in 1999. After 2005, the quantity sold on the largest contract begins to decline for deregulated utilities, coincident with the rise in contract prices shown in panel (a). These figures are consistent with contracts at low prices expiring around 2005 and being replaced by more expensive ones.

6.2 A Case Study of Delayed Effective Deregulation: Illinois

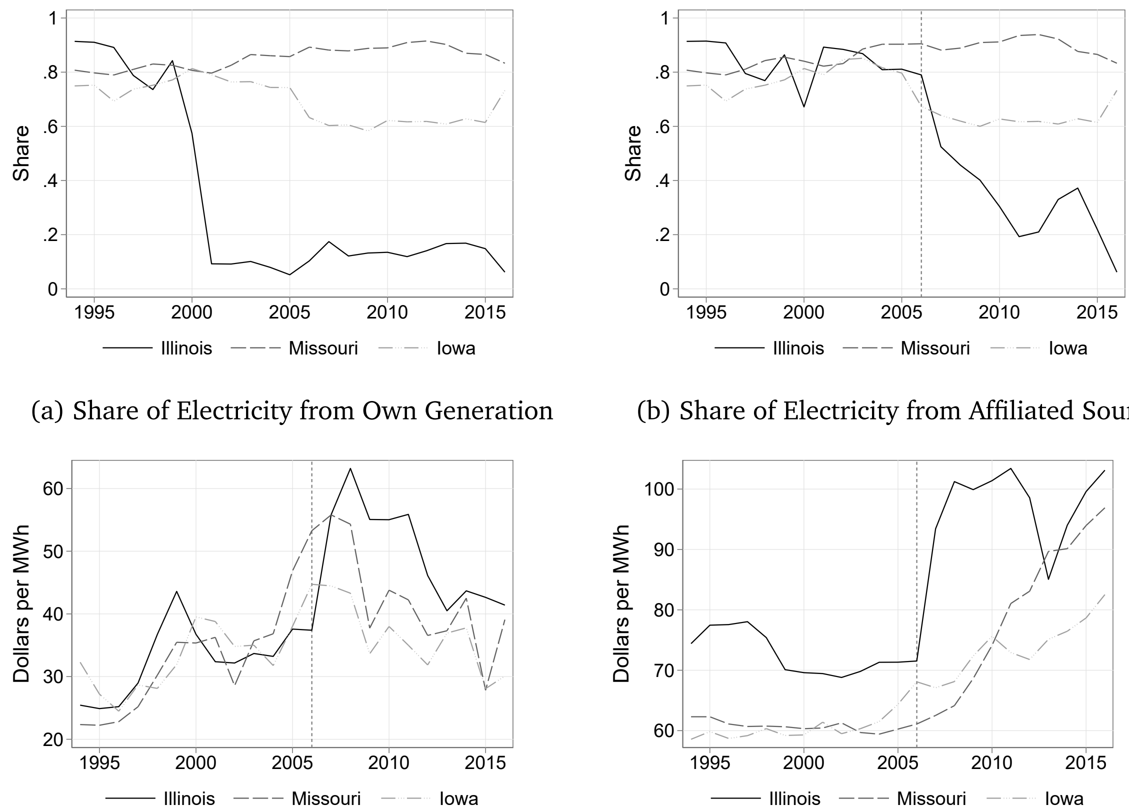
To help illustrate how the timing of deregulation was delayed by state-specific measures, we present Illinois as a case study. In the 1990s, Illinois' electricity rates were among the highest in the United States. Motivated by these high prices, Illinois lawmakers passed the Consumer Choice Act in 1997, which encouraged large investor-owned utilities to divest their generation assets and allowed for independent companies to supply electricity to commercial customers. For residential customers and small businesses, rates were lowered by 15 percent and frozen for 10 years. In 2002, retail choice was extended to residential and small commercial customers, thus allowing for competitive supply in the downstream market.

Within a few years, the investor-owned utilities in Illinois had sold off their complete portfolio of generation assets. This large change to the market is illustrated in panel (a) of Figure 12. The solid black line represents the share of sources that investor-owned utilities obtained from their own generation. The remainder is obtained by purchasing electricity from other producers. The share of electricity sourced from own generation fell from above 80 percent at the time of the restructuring initiatives to 10 percent by 2001.

For comparison, we construct two reference groups: (1) investor-owned utilities in Missouri and (2) investor-owned utilities in Iowa. Missouri is a neighboring state and its largest utility, Union Electric, is part of the Ameren group that owns the utilities serving a large portion of Illinois. Iowa is also a neighboring state, and its largest utilities serve part of northwest Illinois. Importantly, neither Missouri nor Iowa passed any deregulation measures in this period. Panel (a) of Figure 12 plots the share of own generation for Missouri utilities in a dashed line and for Iowa utilities in a dash-dot line. While deregulated firms in Illinois divested nearly all of their generation assets, the regulated firms in Missouri and Iowa continued to obtain the vast majority of their electricity from own generation.

Even though deregulated firms legally divested themselves of generation assets quickly, the actual restructuring of the upstream market came about more slowly. Panel (b) of Figure 12 plots the share of electricity obtained from affiliated companies, which combines both own generation and purchases from companies belonging to the same parent company. The share of purchases from affiliated companies did not fall until 2007. In practice, Illinois utilities split into subsidiary companies and signed long-term purchase agreements with each other at the time of divestiture. The last year of these contracts (2006) is indicated by the vertical dashed line. Even at the end of the sample, some fraction of the electricity is still purchased from

Figure 12: Timing of Deregulation: Illinois



(a) Share of Electricity from Own Generation

(b) Share of Electricity from Affiliated Sources

(c) Upstream (Wholesale) Prices

(d) Downstream (Retail) Prices

Notes: Panel (a) of the figure displays the share of incumbent utilities' total sources provided by own generation for Illinois, which deregulated, and Missouri and Iowa, which did not. Panel (b) plots the share of incumbent utilities' total sources provided by affiliated sources, which include both own generation and purchases from companies belonging to the same parent company. Panels (c) and (d) display average wholesale purchase prices and retail prices, respectively. The year 2006, which is the final year of several long-term contracts between affiliated companies, is indicated by a vertical dashed line.

affiliated companies, raising the possibility that aspects of vertical integration might still be at play in the market.

In the downstream market, consumers were slow to switch from the incumbent utilities due to the price caps that kept utility rates low. The price cap on rates expired in 2007, and many customers switched to independent retailers in that year. Thus, effective deregulation, measured by the impact on market restructuring, did not occur in Illinois until roughly 2007, when most wholesale transactions were between independent parties and retail choice became much more common.

Though deregulation was expected to bring down prices, wholesale electricity prices in Illinois increased sharply in 2007, when contracts expired and deregulation had effectively taken place. This is illustrated in panel (c) of Figure 12. Before 2007, the quantity-weighted purchase price for deregulated utilities in Illinois followed a similar path to prices in Missouri and Iowa. After effective deregulation, wholesale prices in Illinois spiked, and then stayed above prices paid by regulated utilities.

Panel (d) of Figure 12 plots the downstream retail prices. The solid line in the plot shows that prices were steady from 1999 through 2006, which corresponds to the period that the rate freeze was in effect. At the expiration of the rate freeze, retail prices spiked. This increase was sudden and large relative to the price patterns observed in Missouri and Iowa.

Note that, according to our calculations of the change in consumer surplus in Table A2, Illinois is the state that benefited the most from deregulation. On average, consumers in Illinois realized *lower* prices than those charged by comparable utilities. In fact, despite the large initial jump in prices after the rate freeze was removed, Figure 12 shows that retail prices in Iowa and Missouri increased at a faster rate than those in Illinois. Until 2010, the figure suggests that Illinois had significantly higher prices than its neighbors.

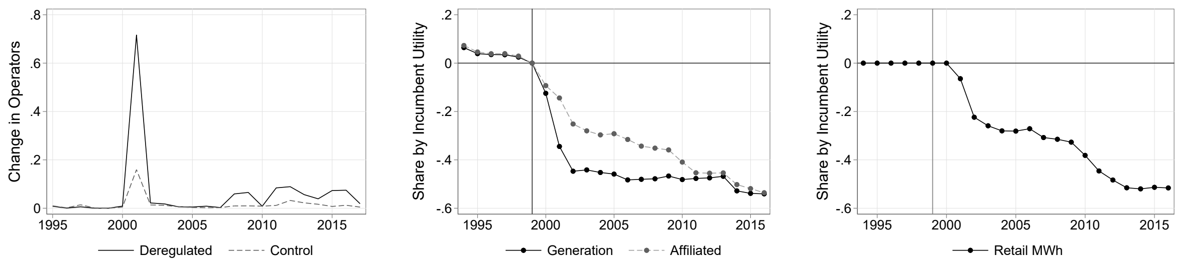
The case study of Illinois illustrates how the effects of deregulation can be delayed for several years, even when legal measures such as vertical separation and competitive markets are introduced quickly. Firms have access to mechanisms (e.g., contracts and umbrella ownership) to maintain a strong degree of vertical integration even when legal entities are vertical separated. Even though Illinois is the most consumer-friendly scenario according to our analysis, wholesale and retail prices increased significantly around the time of effective deregulation.

6.3 Aggregate Delays in Effective Deregulation

Here, we present the estimated delays arising across all deregulated utilities in our sample. First, in panel (a) of Figure 13, we plot the share of generation that reported a new operator from the previous year. Consistent with the narrative of divestiture, approximately 70 percent of generated MWh was under a new operator in 2001. This event is an extreme outlier in the graph, as no more than 10 percent change operators outside of 2000–2002. Next, we consider the difference-in-difference estimates for shares of the incumbent utility. Panel (b) shows our measure of effective deregulation in the upstream market. The solid black line shows the change in the share of aggregate retail consumption that was generated by incumbent utilities. The generation shares fell steeply from 1999 to 2002, with a drop of 44 percentage points. A few additional separations occurred in later years, with the total decline in generation shares reaching 54 percentage points by 2016. We do not observe a decline of 100 percentage points for two reasons. First, deregulated utilities were obtaining only roughly 80 percent of their consumed electricity in 1999 from generation, providing an upper bound for the effect of deregulation. Second, not all utilities in deregulated states were forced to separate generation from retail. For example, in Texas, only IOUs in the ERCOT region were affected. The other IOUs continued to operate as vertically integrated entities.

The grey dashed line shows the affiliated generation share, which captures all generation

Figure 13: Apparent versus Effective Deregulation



(a) Generation Operators (b) Upstream Utility Share (c) Downstream Utility Share

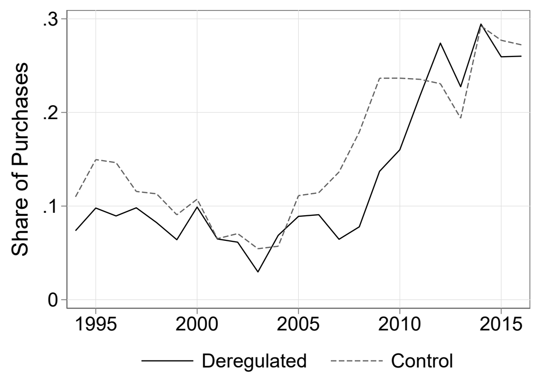
Notes: Figure shows changes in upstream and downstream markets after deregulation. Panel (a) plots the raw share of generation that changed operators from one year to another. Panels (b) and (c) present difference-in-differences matching estimates of changes in the incumbent utility's share of the upstream wholesale market and the downstream retail market. Panel (a) plots a utility's share of quantity demanded provided by its own generation and by all affiliated sources. The gap between the two lines indicates a delay between apparent deregulation and effective deregulation attributable to contracts and umbrella ownership. Panel (b) shows the change in the incumbent utility's share in the downstream retail market.

occurring from utilities and generators owned by the same parent companies. This measure proxies for the long-term contracts signed my several utilities with their generators at the time of separation. The grey dashed line shows that the actual changes to the wholesale market lagged the apparent changes for many years. Though the naive share of competitive generation (i.e., one minus the point estimates in the graph) had increased by over 40 percentage points in 2002, this actual share of competitive generation did not cross this threshold until 2010, after accounting for umbrella ownership across generators and utilities. By 2011, our measures converge, which is consistent with the expiration of the initial contracts and the completion of the transition to a competitive wholesale market.

This narrative lines up with the changes in costs we observe in Figure 5. From 2000 through 2004, while many of these contracts were in effect, generation costs and wholesale costs barely changed. Coincident with the decline in affiliated generation shares starting in 2005, generation costs fell and wholesale markups increased. Taken together, these patterns are consistent with utilities signing long-term contracts at prevailing rates with their separated generation facilities, which delayed the onset of competitive markets for many years. The timing of these cost increases contribute to the larger increases in prices we observe starting in 2006.

A second restriction that delayed the onset of competitive retail markets was the practice of implementing retail rate freezes in deregulated states. These rate freezes kept retail prices low, making the existing utility attractive to consumers and effectively discouraging new entrants. As shown in panel (b) of Figure 5, deregulated utilities saw a decrease in retail markups from 2000 to 2008. These rate freezes could have delayed the transition to competitive retail markets. As shown in panel (b) of Figure 13, competitive retailers obtained roughly 30 percent of the market by 2003. The transition plateaued at this level for several years. Beginning in 2007, the retail

Figure 14: Share of Purchases from ISOs and Power Pools



Notes: Figure displays the shares of purchased electricity obtained from ISO wholesale markets and power pools, for utilities in deregulated and control states. The residual shares are from bilateral contracts with electricity suppliers.

market saw a gradual increase in competitive providers, reaching 52 percent of the market by 2016.

7 Possible Alternative Explanations

In this section, we discuss other events that had an impact on electricity prices and costs that could potentially play a role explaining our findings. Overall, we find that the weight of the evidence points the substantial role of market power in explaining the increase in prices and markups that we observe in deregulated states.

7.1 ISO Markets

During the restructuring process, transmission assets covering areas much larger than a single utility's service area were put into the hands of an independent operator. This served two purposes: First, to grant easier access to independent generators who wanted to sell energy into the market. Second, to allow for trade across larger areas as a potential channel to reduce costs by sourcing energy from low cost plants. Evidence indicates that central dispatch by regional transmission operators has indeed reduced costs (Cicala, 2022).

Our findings suggest that market power in the wholesale market started increasing shortly after ISO organized markets started operating.[41] Nonetheless, there are several reasons why the opening of centrally dispatched electricity markets is unlikely to lead to the observed increase in market power. First, we would expect ISO markets to strengthen competition rather than weaken it, since they connect a larger number of players and have transparent market clearing prices. Second, even if they increase generators' market power, the share of electricity that

[41]For example, the Midwest market (MISO) started operating in 2005 and the New England ISO in 2004.

utilities purchased from ISOs in those early years was fairly low. Figure 14 plots the share of purchased power coming from ISO markets and power pools, which were the predecessors to ISOs. Before 2008, sales via these centralized markets accounted for less than 15 percent of overall wholesale transactions. As of 2016, the vast majority of all purchased power was through traditional bilateral contracts—not ISOs.[42]

Further, ISO markets are not exclusive to restructured states. For instance, only 2 of the 10 states belonging to MISO in 2005 were restructured, and MISO is the second largest ISO after PJM. Figure 14 shows that the share of purchased electricity from ISOs was roughly similar across deregulated and control states. Since our analysis compares utilities in restructured and regulated states, we think that it is unlikely that the observed difference in market power would come from ISO purchases.

Finally, the increase in wholesale markups we observe is not restricted to one market mechanism. Deregulated states see relative increases in both spot market prices (from ISOs and power pools) and bilateral contract prices. Though prices in spot markets tend to track marginal costs more closely, the high-level patterns are similar in the bilateral contract market. Figure A7 in the appendix plots the average purchase prices for deregulated and control utilities from ISOs and power pools compared to bilateral contracts. The plots indicate that wholesale prices in deregulated states realized relative increases of roughly 10 dollars per MWh from both spot markets and bilateral contracts.

7.2 Stranded Costs

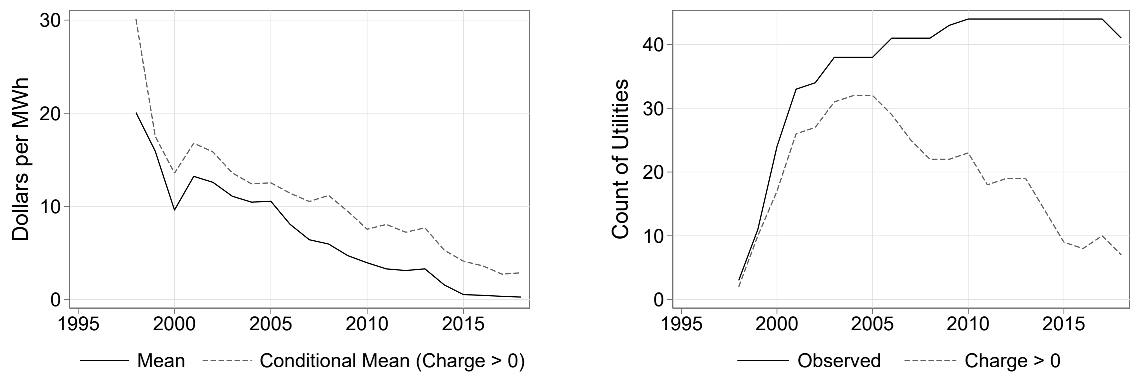
During restructuring, most utilities reached agreements with state regulatory authorities to levy additional charges on their customers related to the move toward deregulation. A common argument by the utilities was that the transition to competitive markets would result in a loss in value of their capital investments, and that they should be compensated for the "stranded" costs of these assets. One question is whether the observed increase in rates reflects these additional charges.

We collected information on transition charges, which covered stranded costs, for 44 large utilities across 16 states that passed deregulation measures.[43] Most of the utilities for which we obtained data levied additional transition charges on their customers; only 6 of them never implemented transition charges. Transition charges were initially very high and decline throughout our sample period. Panel (a) in Figure 15 shows the mean of these additional charges over time. This decline holds even if we condition the mean on utilities with positive stranded costs in each period, thus dropping utilities as their window for stranded cost recovery ends. As shown in panel (b), individual utilities phase out stranded costs starting in 2006. The solid line

[42] If we also account for own generation, the share from ISOs is even smaller. The share from own generation is larger in control states.

[43] The data were obtained from utility ratebooks or the relevant state regulatory commission.

Figure 15: Transition Charges and Stranded Costs



(a) Mean Transition Charges

(b) Count in Sample

Notes: Figure displays the transition charges levied on customers in deregulated utilities to cover stranded costs and other features of restructuring. Panel (a) plots the mean charges (solid line) and the condition mean for positive charges (dashed line). Panel (b) plots the count of utilities with reported transition charges (solid line) and the count of utilities with positive charges (dashed line).

shows the count of utilities for which we have stranded costs measures, and the dashed line shows the count of utilities with positive costs.

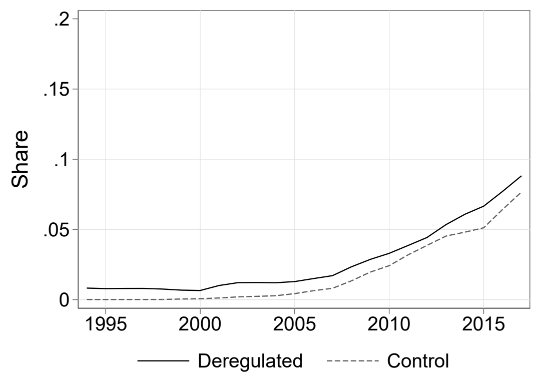
Thus, coinciding with the time we observe effective deregulation and large markup increases, we observe declines in stranded costs and transition charges, with many utilities phasing them out altogether. Though we do not have a complete panel of all stranded costs, we find it very unlikely that they account for the observed increase in prices in deregulated states. The trends in stranded costs move in the opposite direction from the price changes we observe; if anything, these costs may mask some of market power effects of deregulation.

7.3 Renewable Portfolio Standards

Renewable portfolio standards (RPS) require utilities to procure a minimum share of the electricity they sell from renewable sources. RPS have the potential to increase prices (Greenstone and Nath, 2020) and might have contributed to increase utilities' costs, since 25 states had passed regulation with this kind of requirement by 2007.

We think RPS are an unlikely explanation for our results for at least two reasons. First, although RPS were more common among restructured states, those that remained regulated adopted them as well. For example, we find that markups and prices started to diverge around 2006. In 2007, 14 restructured states and 7 regulated states had adopted RPS (Greenstone and Nath, 2020). Second, despite RPS adoption being more likely in deregulated states, the gradual increase in share of generation coming from renewable sources has been similar across the two groups. A possible explanation for this is that at the point of adoption, the requirements put

Figure 16: Share of Generation from New Renewable Resources



Notes: Figure displays share of generated electricity from renewable resources in deregulated and control states. The plot reflects wind, solar, and geothermal sources. Hydropower is excluded because RPS requirements have had little impact on hydropower sources.

in place by RPS were not stringent. To illustrate this, Figure 16 shows the share of generation coming from renewable resources—wind, solar, and geothermal—in deregulated and control states.[44] The figure shows that the shares are nearly identical across the two groups, and they increase at the same gradual rate starting in 2008.

7.4 Other Cost Shocks

Since the restructuring process started, the electric industry has received several cost shocks from two main sources: fuel prices and environmental regulation. How these shocks affected a utility's cost structure depends on the utility's initial fuel mix since, for instance, more stringent environmental regulation will have a stronger effect on costs for utilities that rely more heavily on coal to produce electricity. A potential concern would then be that this initial difference in fuel mix determined how firms were affected by cost shocks, and not the restructuring process.[45]

Our matching approach allows us to deal with this concern, since each utility in a restructured state is compared to utilities in regulated states with a similar fuel mix in 1994. Though our empirical approach compares utilities that in principle would be similarly affected by these cost shocks, it remains vulnerable to variation coming from changes in the fuel mix that took place after 1994. We do not necessarily want to control for entry and exit decisions that took place after the deregulation process had started, as these decisions may have been caused by the deregulation process. If, for instance, deregulated markets attracted more entry by cleaner

[44]Hydropower is excluded because hydropower plants were not the target of RPS requirements. From 2001 through 2016, the share of hydropower generation has remained roughly flat across deregulated and control states.

[45]For example, the Energy Policy Act of 2005 introduced several subsidies and environmental requirements at the federal level, which had varying effects on different types of generators.

plants, or by gas plants that could take advantage of the cheaper gas, this is something that we we can include in our estimates of cost efficiencies. In our data, we observe similar trends in aggregate generation by fuel types across the two groups.[46]

A related concern is that plants may choose emissions compliance strategies that differentially affect their cost structures. Fowlie (2010) compares compliance strategies between restructured and regulated coal plants in response to an emissions trading program introduced in 2006 to regulate NO_X, an ozone precursor. The program affected plants in 19 states, of which 12 were restructured. Because rate-of-return regulation creates stronger incentives for capital investment, regulated plants chose more capital intensive compliance options than plants in restructured states. This implies that environmental regulation could potentially have increased fixed cost for regulated plants and variable costs for restructured plants. If compliance raises variable costs that we do not measure, we could potentially overstate the changes in markups in restructured states. Despite this, compliance costs would not likely explain the large magnitudes that we observe. Engineering estimates of operating compliance costs taken from Fowlie (2010) indicate that the maximum difference between common compliance technologies is around 7.5 dollars per MWh, which is much less than the markup increases that we find (see Figure 4). Moreover, these costs are not much more than the decrease in fuel cost in restructured utilities over that period (see Section 4.3). Thus, such regulations are not likely to generate large increases in variable costs in restructured states.

8 Conclusion

We present a detailed analysis of the evolution of electricity prices and costs from 1994 until 2016. Our analysis spans the implementation of state-specific deregulation measures that began in the late 1990s, which included the introduction of market-based prices. Compared to utilities in states that stayed regulated, deregulated utilities realized higher prices but lower average and marginal costs. Overall, markups increased substantially. Our findings are consistent with the exercise of market power in deregulated markets, particularly at the wholesale level. Generation facilities were able to charge prices at substantial markups above costs, and the vertical separation of generation and retail allowed for additional price increases due to double marginalization.

For our analysis, we construct a unique firm-level dataset that includes firm-to-firm transactions and umbrella ownership that links subsidiaries to the same parent/holding company. We find that changes in prices and markups increased over time because long-term contracts and umbrella ownership delayed the intended changes in vertical market structure. Thus, our research highlights the importance of accounting for intermediate degrees of vertical integration

[46] The only meaningful difference in our data is that control states became relatively less reliant on coal and more reliant on natural gas during our sample period.

to understand the consequences of deregulation and related policies.

Our findings do not necessarily imply that electricity markets should remain regulated, but rather emphasizes the importance of careful oversight of deregulated markets and the consideration of market power in market design. Further research is needed on how to organize markets such that consumers can benefit from lower prices, as well as understanding the longer-run effects of deregulation that arise from changes in investment and environmental compliance efforts.

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Appendix

For Online Publication

A Details of Dataset Construction

In this section, we provide additional details about the construction of the dataset and state-specific deregulation.

A.1 Dataset Construction Details

Our dataset comes from several publicly-available data sources available from EIA and FERC. All data is reported annually. We construct our panel from 1994 through 2016.

Utility-level operational data were collected from form EIA-861. These data contain aggregate measures of generation, purchases, sales for resale, and retail sales for each utility. We combine these data with detailed retail and delivery sales (prices and quantities) by customer type, which is also from form EIA-861. We restrict our analysis to three types of customers: residential, commercial, and industrial, which account for the vast majority of retail consumption.[47] These data are reported at the utility-state level; for utilities that are located in multiple states, the combination of retail MWh and delivery MWh allows us to calculate each utility's total MWh serviced in each state. When constructing our data at the utility-state level, we scale aggregate variables from the operational data by the MWh serviced in each state (for multistate utilities only).

We obtained power plant generation data from forms EIA 759 between 1994 and 2000, EIA 906 between 2001 and 2007, and EIA 923 between 2008 and 2016. We used form EIA 906 for non-utilities generation during years 1999 and 2000. These data provide generator-specific measures of net generation and fuel consumption. For marginal costs, we use the average fuel cost of the upper quartile of MWh generated for all generators in a utility service area. We construct generator-specific and utility-specific marginal costs using the realized efficiency of each generator and the relevant fuel types. Unit fuel costs are estimated from purchased fuel receipts, which are reported in form EIA 423 for years prior to 2008 and form EIA 923 from 2008 onwards. When the unit cost of a given fuel was not available for a given power plant, we imputed it using the average unit cost for that fuel in the state and year. We obtain data on power plant operators from form 906, which we used to link each power plant to the utility

[47] The excluded customer types are transportation, public, and other.

that owned it pre-deregulation.[48] We use capacity data at the power plant level from EIA Form 860, which contains information on dates of initial operation and retirement.

Data on energy purchases were obtained from FERC Form 1. In this form, utilities report the identity of all sellers from which they purchased, as well as quantity, price, and other information. We identified whether each buyer-seller pair was affiliated via umbrella ownership under the same parent company by combining the information in a report on investor-owned utilities by the Edison Electric Institute (2019) and internet searches. We use the FERC Form 1 data to calculate the share of purchases from affiliated companies and the share of purchases from ISOs.

We manually constructed a panel of mergers and divestitures among the utilities in our dataset. We retroactively apply mergers to the entire panel and also undo divestitures, thus aggregating utilities that were ever part of the same entity into a single entity from the beginning to the end of the sample.

A.2 State-Specific Deregulation

To measure the impact of deregulation, we divide our sample into utilities in states that allowed for market-based electricity prices and those in states that continued with a state-sponsored monopoly and regulated rates. States that allowed for market-based electricity prices also enacted restructuring measures to allow for competitive entrants in the generation market (upstream) and in the retail market (downstream). Typically, incumbent utilities in deregulated states were no longer permitted to own generation facilities, but they were allowed to continue to operate downstream. Thus, retailers in deregulated states had to obtain electricity from a wholesale market, and consumers could choose between a regulated rate from the incumbent utility and market-based prices from independent retailers.

For each state, we identify whether deregulation measures were enacted, and when the measures legally came into effect. The 17 states that implemented deregulation measures in our period (1994–2016) are reported in Table A1, along the year of implementation. Upstream deregulation measures correspond to the vertical separation of a utility from generation facilities as well as an explicit allowance of competitive electricity suppliers. Downstream deregulation measures correspond to the introduction of a market for alternative retail suppliers. All of the states implemented these measures between 1998 and 2002, and the upstream and downstream legal changes typically occurred at the same time. Michigan is a notable exception, as they allowed for downstream competition but did not restructure the upstream market.

Five states—Arizona, Arkansas, Nevada, and Montana—initially passed deregulation measures but later rescinded them. We remove these four states from our analysis. We focus on investor-owned utilities (IOUs) that generated electricity in 1994. Because Nebraska and Ten-

[48] In the beginning of our sample, the operators coincided with ownership.

Table A1: First Year of Deregulation, by State

State	Implementation Year
NY	1998
RI	1998
CA	1999
NH	1999
MA	1999
ME	1999
CT	2000
DE	2000
MD	2000
NJ	2000
PA	2000
IL	2001
OH	2001
MI	2002
OR	2002
TX	2002
VA	2002

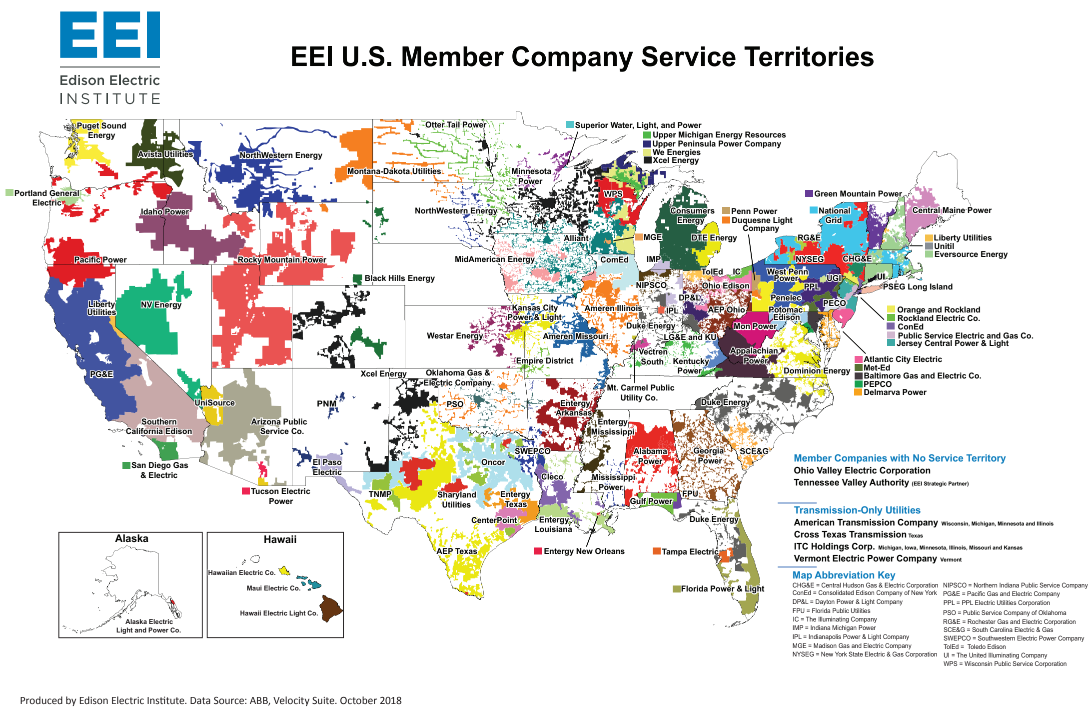
Notes: Table indicates the year initial deregulation measures came into effect for the listed states. For most states, this corresponds to when utilities began to divest generation assets. Michigan (MI) is an exception that did not pass a measure to deregulate the upstream market. Four states (AZ, AR, NV, and MT) initially passed deregulation measures but later rescinded them. These four states are omitted from our analysis.

nessee do not have utilities that meet these criteria, we also remove them from the analysis.[49] We are left with 17 states that introduced competitive markets and 25 states that did not. Our main sample consists of 78 treated utilities that were subject to deregulation measures and 75 utilities control utilities that were not.

Figure A1 presents a map of the geographic service areas for the utilities in United States. Our analysis focuses on the subset of these utilities that were in deregulated and control states that meet the above criteria.

[49] Nebraska does not have IOUs in this time period. In Tennessee, all generation comes from the federally operated Tennessee Valley Authority.

Figure A1: Areas Served by Investor-Owned Utilities



Notes: Figure displays the geographic service territories for investor-owned utilities in our sample as of 2018. Source: Edison Electric Institute.

B Conceptual Framework

Consider a regulator charged with implementing a regulated monopoly or market competition in an industry. The regulator seeks to maximize consumer welfare. Since consumer welfare is higher when consumers pay less, regulator chooses the design that minimizes consumer prices.

Let P_r denote regulated prices and P_m denote market-based prices. In the monopoly regime, prices are regulated to reimburse costs (c_r) and provide a regulated markup (μ_r) to reimburse the utility for its fixed-cost investments under rate-of-return regulation. The problem can be written as:

$$\min\{P_r, P_m\} \tag{4}$$

$$\text{s.t.} \quad P_r = c_r \cdot \mu_r. \tag{5}$$

Deregulation entails (i) the vertical separation of the upstream and downstream markets, (ii) entry by competitors in both markets, and (iii) prices determined by market forces. P_m may differ from P_r through different incentives to reduce costs and charge markups on marginal costs.

If the market is restructured, the utility is vertically separated and a wholesale market is created, such that the utility no longer generates its own electricity and now has to purchase it in the wholesale market at a price $w(c_m)$. This price will be a function of the marginal cost of production, c_m, which may be different from c_r because plants' operation, dispatch, and investment may change after restructuring:

$$P_m = w(c_m) \cdot \mu_m. \tag{6}$$

For simplicity, assume that $\mu_m = \mu_r$, i.e., the regulator does not change the permissible markup over procurement costs. By holding the retail markup fixed, we see from these two equations that the change in prices after deregulation depends on how the wholesale price w compares to the marginal cost under regulation c_r:

$$P_m < P_r \iff w(c_m) < c_r. \tag{7}$$

We can decompose this relationship into two components. The first reflects potential efficiency gains, which translate into lower costs under restructuring: $c_m < c_r$. The second component is the relationship between w and c_m, which depends on market power in the wholesale market. If the wholesale market is perfectly competitive, $w = c_m$. In this case, any efficiency gains resulting in $c_m < c_r$ will be passed on to prices, so $P_m < P_r$. Thus, a regulator anticipating perfectly competitive markets and efficiency gains would prefer market-based competition. This set of expectations rationalizes the widespread deregulation efforts observed in the U.S.

If the wholesale market is not perfectly competitive, upstream suppliers will charge a markup and the wholesale price will be

$$w = \frac{c_m}{1 + \frac{1}{\varepsilon}}, \tag{8}$$

where ε is the elasticity of the demand in the wholesale market. Suppliers will charge a positive markup as long as they face a demand that is less than perfectly elastic.

In addition, if the retail market is not perfectly competitive, retailers may be able to charge a markup μ_m that exceeds the regulated markup, μ_r. Thus, the presence of double marginalization—through larger retail margins ($\mu_m > \mu_r$) in addition to wholesale margins ($w - c_m$)—could outweigh the the efficiency gains that have been documented in the literature (Fabrizio et al., 2007; Cicala, 2015, 2022; Jha, 2020).

A regulator choosing between a regulated monopoly and market-based competition will choose deregulation if she expects efficiency gains to outweigh equilibrium markups, which depend on the degree of market power in the industry. If equilibrium markups are large relative to the efficiency gains, a regulated monopoly will ensure lower retail prices. This illustrates the important role of market power in designing regulations.[50]

[50] In this simple framework, which mirrors the discussion around deregulation in the U.S., the regulator's decision hinges on which regime provides the lowest prices. Regulators may also be concerned about elements outside of our framework, such as energy reliability and pollution. For example, pollution externalities could make higher prices more desirable from a welfare perspective. We believe that such considerations are better dealt with policies that target them directly (e.g., with taxes) rather than an inefficient pricing mechanism that may distort the market in other dimensions.

C Heterogeneity Across States

In the main text, we focus primarily aggregate effects across all states that implemented deregulation measures. Here, we examine the heterogeneity across states by calculating the average price effects using the utility-specific coefficients from our matching approach. To calculate the potential impact on consumer surplus, we assume an elasticity of -0.315, which is the estimated 5-year elasticity from Deryugina et al. (2019). We use the estimated price changes, the implied impact on quantities using the demand elasticity, and the realized values for prices and quantities to estimate the dollar impact on consumer surplus.

Table A2 reports the results. Panel (a) presents the annual averages over the full post-deregulation sample, from 2000 through 2016. On average, consumers paid 106 dollars per MWh for 1.4 petawatts of electricity in investor-owned utilities in deregulated states. We estimate an average price increase of 6.4 percent, corresponding to a decrease in quantity of 1.6 percent and an annual loss of $8.7 billion in consumer surplus.

We estimate some heterogeneity across states. Most deregulated states realized meaningful price increases, with 9 states realizing price effects exceeding 5 percent. We estimate that consumers in some states did benefit from deregulation, with consumers in Virginia and Illinois realizing meaningful decreases in prices.

As indicated by the earlier analysis, the effects increased over time. Panel (b) presents the annual results for the period 2006 to 2016, when we observe the realization of effective deregulation. We discuss timing in greater detail in the following section. From the later period, the estimated annual effects are greater, with aggregate price increases of 8.0 percent and annual loss in consumer surplus of $11.7 billion.

As a robustness check, we repeat the exercise using an alternative measure of price, which is an estimate of the realized retail prices using a within-state measure of delivery fees and retail prices from alternative suppliers. The results are reported in Table A3 in the Appendix. Overall, the results are similar but smaller in magnitudes, with annual losses in consumer surplus of $5.5 billion over the full sample and $7.5 billion from 2006 to 2016.

Table A2: Estimated Annual Impacts

(a) 2000–2016

State	Realized Values Price ($/MWh)	Quantity (MWh)	Percent Change Price	Quantity	Dollar Change Consumer Surplus
CA	138.91	189,195,740	21.4	-5.8	-4,426,780,852
NY	158.02	133,179,152	11.8	-2.9	-2,137,372,377
TX	88.43	250,568,361	9.1	-2.6	-1,627,322,560
CT	147.43	28,525,814	15.4	-3.9	-547,854,651
MD	104.57	58,544,944	8.9	-1.9	-516,473,654
MA	150.86	25,356,908	15.9	-4.3	-507,799,388
OH	83.89	135,971,028	5.6	-1.9	-499,096,124
OR	76.39	33,164,301	11.0	-3.2	-238,194,378
RI	134.22	7,624,773	17.7	-4.7	-149,456,983
NJ	123.81	72,405,815	1.4	-0.2	-122,194,363
NH	150.45	7,805,263	4.1	-0.8	-46,196,355
DE	99.28	8,657,489	1.7	-0.0	-18,724,126
ME	120.47	10,807,305	-0.9	0.3	13,456,753
MI	90.30	93,349,655	-1.6	0.7	129,487,139
VA	75.82	88,860,749	-4.0	1.3	272,619,229
PA	96.12	137,282,241	-3.5	1.2	477,672,144
IL	81.85	125,157,578	-14.5	4.9	1,728,510,030
All	106.30	1,406,457,117	6.1	-1.5	-8,215,720,517

(b) 2006–2016

State	Realized Values Price ($/MWh)	Quantity (MWh)	Percent Change Price	Quantity	Dollar Change Consumer Surplus
CA	146.41	194,617,260	24.2	-6.5	-5,284,272,352
NY	169.62	136,817,754	14.3	-3.5	-2,762,366,569
MD	125.62	57,191,583	18.8	-5.2	-1,097,300,888
TX	93.87	263,422,568	5.5	-1.5	-1,086,200,883
CT	172.10	28,144,316	26.1	-7.0	-958,223,951
OH	93.19	134,984,849	7.7	-2.6	-741,017,274
MA	167.80	25,618,216	21.1	-5.8	-711,361,414
NJ	137.55	73,251,746	5.7	-1.7	-512,230,406
OR	84.67	33,369,197	11.1	-3.3	-269,306,251
RI	148.98	7,665,444	25.2	-6.7	-220,400,082
NH	169.17	7,901,845	10.7	-2.8	-122,521,001
DE	118.60	8,391,985	9.1	-2.7	-81,249,387
MI	101.60	92,752,418	0.7	-0.2	-65,437,606
ME	128.66	11,042,416	-1.6	0.5	24,723,114
VA	82.66	92,361,718	-4.3	1.5	331,498,812
PA	104.26	141,719,115	-3.6	1.3	545,492,695
IL	88.25	128,082,698	-15.3	5.3	2,019,309,506
All	115.68	1,437,335,127	7.5	-1.8	-10,990,863,936

Notes: Impact on consumer surplus is calculated using the estimated price changes, the implied impact on quantities assuming a price elasticity of -0.315, and the realized values of prices and quantities. Price is the average bundled price weighted by the share of residential, industrial, and commercial customers served by each utility.

Table A3: Estimated Annual Impacts Using Alternative Price Measure

(a) 2000–2016

	Realized Values		Percent Change		Dollar Change
State	Price ($/MWh)	Quantity (MWh)	Price	Quantity	Consumer Surplus
CA	136.31	189,195,740	19.2	-5.3	-3,988,145,520
TX	88.43	250,568,361	9.1	-2.6	-1,627,322,070
NY	149.44	133,179,152	5.9	-1.5	-1,077,568,693
CT	146.29	28,525,814	14.5	-3.7	-519,400,405
MA	148.10	25,356,908	13.8	-3.8	-443,875,675
MD	100.57	58,544,944	4.9	-0.9	-294,981,097
OR	76.19	33,164,301	10.7	-3.1	-231,901,282
OH	81.25	135,971,028	2.4	-1.1	-161,121,391
RI	131.45	7,624,773	15.3	-4.1	-129,918,711
NJ	123.82	72,405,815	1.4	-0.3	-126,038,203
ME	120.47	10,807,305	-0.9	0.3	13,456,656
DE	94.39	8,657,489	-3.1	1.4	22,778,069
NH	136.13	7,805,263	-5.6	1.9	60,924,364
MI	89.32	93,349,655	-2.7	1.0	219,351,890
VA	75.82	88,860,749	-4.0	1.3	272,931,614
PA	91.66	137,282,241	-7.8	2.5	1,072,116,308
IL	80.33	125,157,578	-16.0	5.5	1,907,274,539
All	103.88	1,406,457,117	3.8	-0.9	-5,031,439,607

(b) 2006–2016

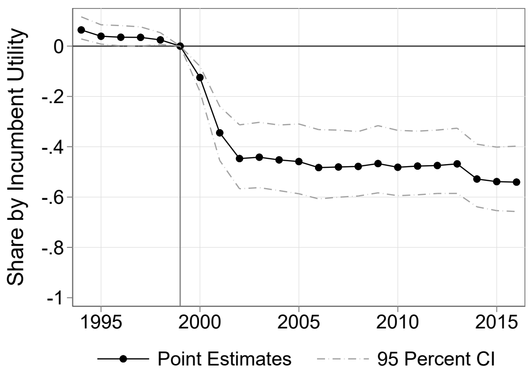
	Realized Values		Percent Change		Dollar Change
State	Price ($/MWh)	Quantity (MWh)	Price	Quantity	Consumer Surplus
CA	143.87	194,617,260	22.2	-6.0	-4,858,046,917
NY	159.72	136,817,754	7.7	-2.0	-1,516,114,355
TX	93.87	263,422,568	5.5	-1.5	-1,086,200,245
CT	170.34	28,144,316	24.9	-6.7	-915,221,756
MD	119.56	57,191,583	13.1	-3.8	-771,345,141
MA	164.49	25,618,216	18.7	-5.3	-635,588,424
NJ	137.43	73,251,746	5.6	-1.7	-508,440,217
OR	84.36	33,369,197	10.8	-3.2	-259,339,288
OH	88.96	134,984,849	2.9	-1.3	-202,687,791
RI	145.01	7,665,444	21.9	-6.0	-192,297,689
DE	111.00	8,391,985	2.1	-0.7	-18,634,737
ME	128.66	11,042,416	-1.6	0.5	24,723,001
NH	147.31	7,901,845	-3.6	1.2	43,029,004
MI	100.12	92,752,418	-0.7	0.3	68,606,369
VA	82.65	92,361,718	-4.3	1.5	332,122,354
PA	97.61	141,719,115	-9.6	3.2	1,458,145,195
IL	86.12	128,082,698	-17.3	6.0	2,275,019,469
All	112.52	1,437,335,127	4.7	-1.1	-6,762,271,169

Notes: Impact on consumer surplus is calculated using the estimated price changes, the implied impact on quantities assuming a price elasticity of -0.315, and the realized values of prices and quantities. Price is a measure of the average price paid by all retail consumers in each utility's service area. It is calculated as the weighted average of the bundled service price and an approximate measure of the retail price to customers of alternative electric suppliers. The approximate measure is constructed as the sum of utility-specific delivery services and the statewide average retail energy price. We do not have utility-specific measures of energy prices from alternative suppliers, and reporting may vary across utilities due to lack of standardization.

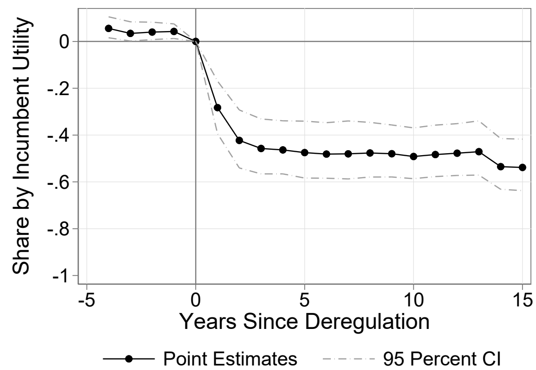
D Robustness Checks and Additional Analysis

Comparison of Event Timing Approaches

Figure A2: Different Choices of Timing



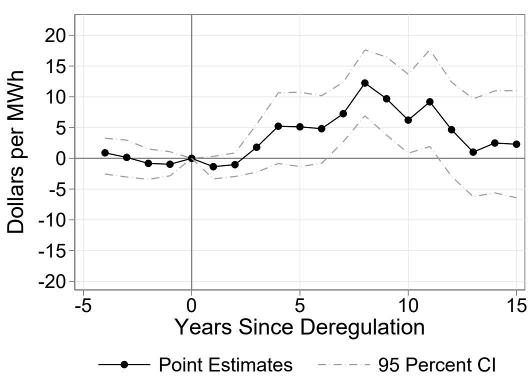
(a) Calendar Time



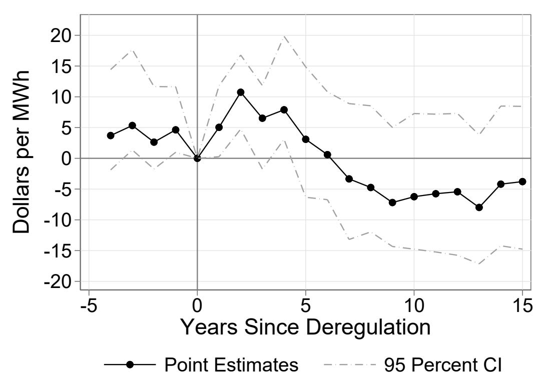
(b) Utility-Specific Event Time

Notes: Figure displays difference-in-differences matching estimates of changes to incumbent utilities share of quantity demanded provide by its own generation. Panel (a) displays the results in calendar years, following the results in the main text. Panel (b) displays the results indexed to time period 0, which represents the year prior to the implementation of deregulation measures in each utility's state. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

Figure A3: Event Study Estimates of Changes in Prices and Costs After Deregulation



(a) Retail Prices

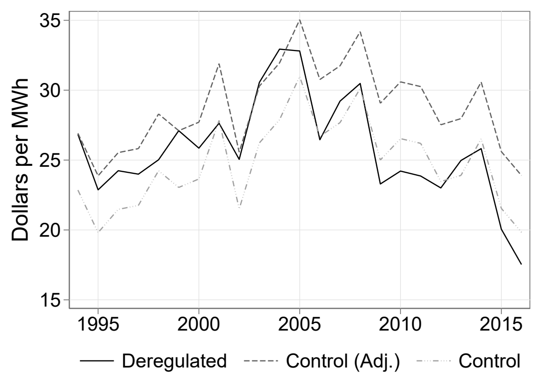


(b) Generation Fuel Costs

Notes: Figure displays difference-in-differences matching estimates of changes in (a) retail prices and (b) fuel costs for deregulated utilities. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to time period 0, which represents the year prior to the implementation of deregulation measures in each utility's state. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

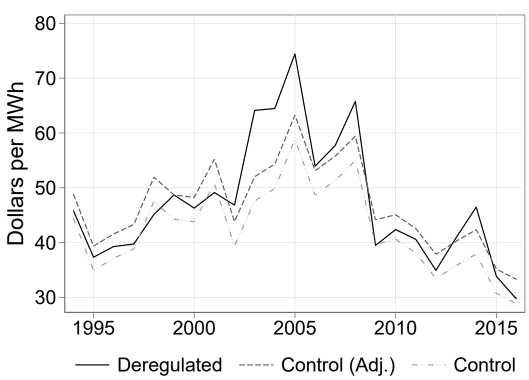
Alternative Measures of Generation Costs

Figure A4: Average Variable Fuel Costs

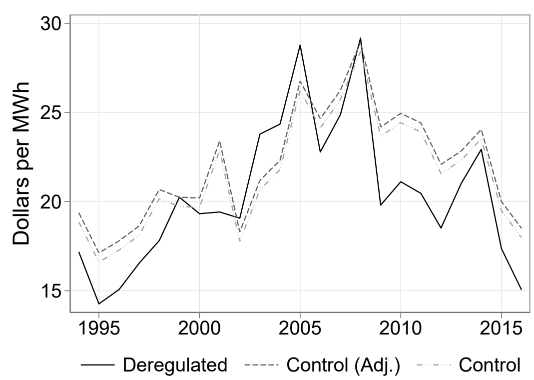


Notes: Figure plots the average fuel costs of generation for all generating facilities in deregulated states (solid black line) and control states (grey line). The dashed line plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

Figure A5: Statewide Fuel Costs



(a) Marginal Costs



(b) Average Variable Costs

Notes: Figure plots the statewide measure fuel costs using our measure of marginal costs and average variable costs. Marginal costs are calculated as the average fuel costs for the 75th percentile and up of MWh generated for all generating facilities in deregulated states (solid black line) and control states (grey line). The dashed line plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

Difference-in-Differences Effects with Average Variable Costs

Table A4: Relative Changes in Prices, Costs, and Markups (AVC)

	(1)	(2)	(3)	(4)	(5)	(6)
	Retail Price	Wholesale Price	Generation Cost (AVC)	Retail Markup	Wholesale Markup	Gross Markup
1999 Values	78.06	42.81	26.61	34.95	17.09	51.40
2000-2005	4.14	−0.42	−2.75	4.87	2.29	6.85
	(1.74)	(2.97)	(2.83)	(2.45)	(4.66)	(3.64)
2006-2011	12.73	3.46	−9.12	9.38	11.60	21.71
	(2.95)	(3.49)	(3.32)	(3.84)	(4.97)	(4.60)
2012-2016	5.83	7.41	−8.63	2.63	14.88	14.60
	(3.83)	(4.18)	(3.32)	(4.10)	(5.39)	(4.98)
2000-2016	7.66	3.16	−6.71	5.62	9.12	14.31
	(2.30)	(2.99)	(2.65)	(2.73)	(4.16)	(3.74)

Notes: Table displays the estimated difference-in-differences matching cofficients for prices, costs, and markups between deregulated and control utilities in dollars per MWh. In this table, costs and markups are calculated using average variable costs. The first row provides the baseline values in 1999, and the remaining rows provide the average effect for the specified time period. Standard errors are displayed in parentheses.

Matching with Geographic Proximity

Here, we report summary statistics (Table A5) and difference-in-differences results (Table A6) when we also match on Census region. The results are very similar to the baseline specification.

Table A5: Characteristics of Deregulated and Alternative Matched Control Utilities in 1994

	(1)	(2)	(3)	(4)	(5)
	Deregulated	Control		Matched Controls	
	Mean	Mean	p-value of Difference from (1)	Mean	p-value of Difference from (1)
ln(MWh Retail)	15.21	15.22	0.977	15.40	0.717
ln(MWh Generated)	14.70	14.60	0.857	14.59	0.891
Marginal Generation Share: Coal	0.50	0.54	0.705	0.53	0.817
Marginal Generation Share: Gas	0.12	0.15	0.639	0.12	0.943
Marginal Generation Share: Nuclear	0.02	0.02	0.763	0.01	0.575
Marginal Generation Share: Oil	0.19	0.07	0.078	0.16	0.735
Marginal Generation Share: Water	0.18	0.20	0.763	0.18	0.960
Marginal Fuel Costs	65.69	37.89	0.137	59.11	0.795
Retail Price	78.76	58.95	0.001	59.78	0.002
Number of Unique Utilities	78	76		72	

Notes: Table displays 1994 characteristics for 78 investor-owned utilities in states that later deregulated and 76 investor-owned utilities in states that did not deregulate. Columns (1) and (2) report the mean characteristics for each group, and column (3) reports the p-value of the difference in means. Column (4) reports the means for matched controls using a nearest-neighbor methodology, and column (5) reports the p-value of the difference in means between matched controls and the deregulated utilities. The first eight variables are used as matching variables, along with Census region.

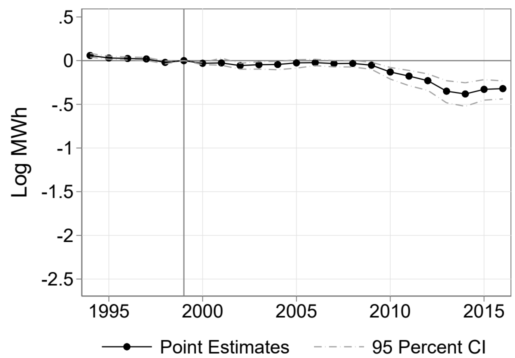
Table A6: Relative Changes in Prices, Costs, and Markups (Geographic Matching)

	(1)	(2)	(3)	(4)	(5)	(6)
	Retail Price	Wholesale Price	Generation Cost	Retail Markup	Wholesale Markup	Gross Markup
1999 Values	78.06	42.81	48.89	34.95	−5.22	29.13
2000-2005	4.14	−0.42	−0.63	4.87	−0.26	4.74
	(1.74)	(2.97)	(2.88)	(2.45)	(4.52)	(3.59)
2006-2011	12.73	3.46	−10.59	9.38	12.30	23.18
	(2.95)	(3.49)	(4.82)	(3.84)	(6.03)	(5.72)
2012-2016	5.83	7.41	−10.83	2.63	16.40	16.80
	(3.83)	(4.18)	(4.92)	(4.10)	(6.56)	(6.01)
2000-2016	7.66	3.16	−7.11	5.62	8.82	14.71
	(2.30)	(2.99)	(3.59)	(2.73)	(4.68)	(4.40)

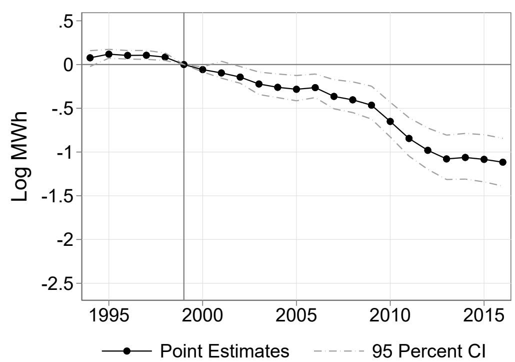
Notes: Table displays the estimated difference-in-differences matching cofficients for prices, costs, and markups between deregulated and control utilities in dollars per MWh. The first row provides the baseline values in 1999, and the remaining rows provide the average effect for the specified time period. Standard errors are displayed in parentheses. The results correspond to a specification with geographic proximity as a matching variable.

Change in Downstream Consumption

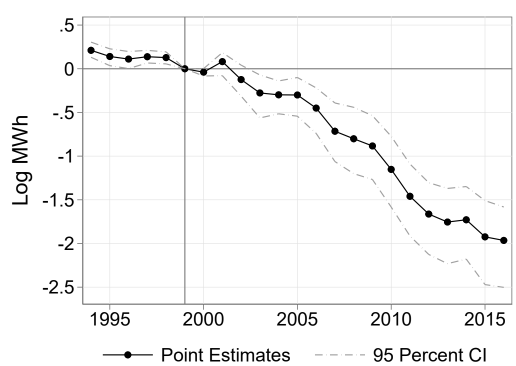
Figure A6: Change in Incumbent Utility Retail MWh (Bundled Service)



(a) Residential



(b) Commercial

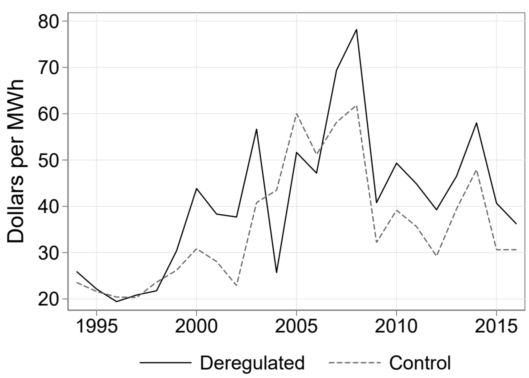


(c) Industrial

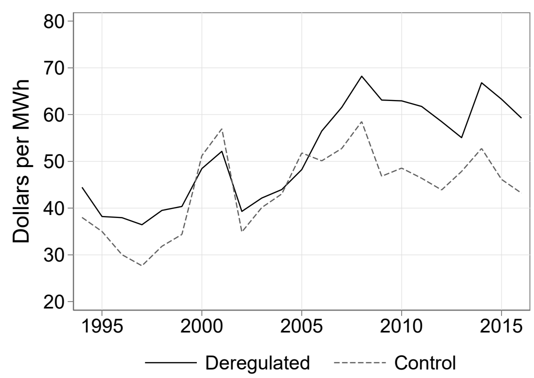
Notes: Figure displays difference-in-differences matching estimates of changes in log MWh for bundled service for deregulated utilities. Bundled service customers are those remaining on regulated rates in deregulated areas. We exclude Texas and Maine, which fully eliminated bundled service. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to 1999, which is the year prior to the first substantial deregulation measures. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

Wholesale Electricity Markets: ISOs and Bilateral Contracts

Figure A7: Wholesale Prices from Spot Markets (ISOs and Power Pools) and Bilateral Contracts



(a) Spot Markets



(b) Bilateral Contracts

Notes: Figure displays the wholesale prices based on utility-level purchases for deregulated states (solid lines) and control states (dashed lines). Panel (a) plots the MWh-weighted average purchase prices from ISO markets and power pools, and panel (b) plots the MWh-weighted average from bilateral contracts.