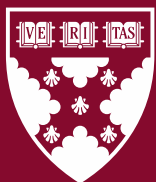


Working Paper 21-095

Do Markets Reduce Prices? Evidence from the U.S. Electricity Sector

Alexander MacKay
Ignancia Mercadal



**Harvard
Business
School**

Do Markets Reduce Prices? Evidence from the U.S. Electricity Sector

Alexander MacKay
Harvard Business School

Ignacia Mercadal
University of Florida

Working Paper 21-095

Copyright © 2021, 2022, 2023, 2024 by Alexander MacKay and Ignacia Mercadal.

Working papers are in draft form. This working paper is distributed for purposes of comment and discussion only. It may not be reproduced without permission of the copyright holder. Copies of working papers are available from the author.

We are grateful for the research assistance of Tridevi Chakma, Laura Katsnelson, Gabriel Gonzalez Sutil, and Catrina Zhang. Previous versions of this paper circulated under the title, “Shades of Integration: The Restructuring of the U.S. Electricity Markets” and “Deregulation, Market Power, and Prices: Evidence from the Electricity Sector.”

Funding for this research was provided in part by Harvard Business School.

Do Markets Reduce Prices?

Evidence from the U.S. Electricity Sector*

Alexander MacKay
Harvard University[†]

Ignacia Mercadal
University of Florida[‡]

March 30, 2024

Abstract

We construct a novel dataset on electricity generation, wholesale transactions, and retail sales to assess the shift from cost-of-service regulation to deregulated, market-based prices in the context of the U.S. electricity sector. Consistent with earlier studies, we find that the costs of generation fell in deregulated markets. However, despite lower generation costs, wholesale prices increased along with utilities' overall expenses on energy. The resulting increase in utility costs can explain a substantial portion of the increase in downstream retail prices. Overall, we estimate that the increase in wholesale margins more than offset the efficiency gains, which can occur when markets are not perfectly competitive.

Keywords: Deregulation, Markets, Market Power, Electricity

JEL Classification: L51, L94, D43, L13, L43, Q41

*We are thankful for detailed comments from several readers and discussants, as well as the comments from numerous seminar and conference participants. We are grateful for the research assistance of Tridevi Chakma, Laura Katsnelson, Gabriel Gonzalez Sutil, and Catrina Zhang. Previous versions of this paper circulated under the title, "Shades of Integration: The Restructuring of the U.S. Electricity Markets" and "Deregulation, Market Power, and Prices: Evidence from the Electricity Sector."

[†]Harvard University, Harvard Business School. Email: amackay@hbs.edu.

[‡]University of Florida, Department of Economics. Email: imercadal@ufl.edu.

1 Introduction

Over the past 50 years, many traditionally regulated industries have seen 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, whether or not deregulation leads to lower prices is theoretically ambiguous. Market-based prices provide incentives for profit-maximizing firms to reduce costs, but they can also yield a larger gap between prices and costs when there are market imperfections. Thus, lower costs may not necessarily yield lower prices.

We study this tradeoff in the context of the restructuring of the U.S. electricity sector. Starting in the late 1990s, regulators and lawmakers promulgated new measures to encourage the use of markets to exchange generated electricity, as opposed to vertically integrated utilities. Important changes at the state level were the divestiture of generation assets by incumbent utilities (a switch from “make” to “buy”) and the shift from regulated, cost-of-service generation to market-based wholesale prices. The previous literature has found that these deregulation measures have led to cost reductions (e.g., Fabrizio et al., 2007; Davis and Wolfram, 2012), but it has not been established that these efficiency gains benefited buyers. Whether or not cost savings are passed downstream matters for the design of electricity markets and assessing welfare impacts, as retail prices have risen sharply over the past 20 years. We address the consequences of deregulation¹ by examining the evolution of average annual wholesale prices and overall utility energy costs.

To understand the impacts to the wholesale market, 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. A primary source of our new data is FERC Form 1, which is an annual report provided by utilities to regulators and is used to determine rates. These data allow us to examine both wholesale prices and the utilities’ overall power production expenses.

The prior literature has focused on data from centralized wholesale markets run by independent system operators (ISOs).² By contrast, our data include not only purchases from these centralized markets but also purchases made through bilateral (firm-to-firm) contracts. From 2000 through 2016, the vast majority—over 85 percent—of wholesale electricity was sold through such contracts. Thus, a key contribution of our paper is to provide a more comprehensive view of the wholesale market, which allows us to characterize the passthrough of generation costs to prices.

Using these data, we compare utilities that were subject to state-specific deregulation poli-

¹We use the term *deregulation* to denote the state-level changes that led to the vertical separation of generators and utilities and enabled generators to sell all of their production at market rates, following other papers in the literature (e.g., Davis and Wolfram, 2012; Cicala, 2015). Several aspects of the sector remained regulated after these changes, similar to how deregulation transpired in other industries. For this reason, and because the sector underwent other changes, the alternative term *restructuring* is often used in the literature.

²See, e.g., Jha and Wolak (2023); Mercadal (2022); Puller (2007); Borenstein et al. (2002).

cies to similar utilities in other states that retained cost-of-service regulation 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.³ We then study how procurement costs have evolved across comparable utilities, analyzing the evolution of wholesale prices and generation costs. Because average upstream energy costs remain a primary component of retail rates, changes in average wholesale prices are also a key channel through which deregulation can affect retail prices.

We find substantial price increases for wholesale buyers in deregulated states relative to buyers in states that remained regulated. However, consistent with earlier findings, generation costs declined in deregulated states, indicating that the higher prices are driven by a larger wedge between generation costs and wholesale prices. Overall, we estimate that wholesale margins—wholesale prices minus the costs of generation—increased by 14.2 dollars per MWh from 2000 to 2016. In magnitudes, this corresponds to 34 percent of 1999 wholesale prices and 18 percent of 1999 retail prices.

We then focus in on the energy costs for incumbent utilities. During the early years of restructuring, utilities realized higher energy costs despite little change to generation costs and market prices. Deregulated utilities, having divested generation assets, were not able to produce as much electricity and were therefore required to purchase more electricity at market prices. Because wholesale prices were higher than generation costs, utility energy costs increased. Downstream, the rates that these utilities charged retail customers—which by regulation were tied to the average expenses on energy—went up. Thus, the early years of restructuring highlight how the shift from make to buy could lead to higher retail prices.

We find that generation costs began to decline in 2006, while, at the same time, wholesale prices increased. The several-year delay can be explained by the fact that, 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. In a competitive market free from market imperfections, we would instead expect wholesale prices to have fallen along with the decline in generation costs.

After 2006, deregulated utilities began to purchase a greater share of electricity from ISO markets, increasing from roughly 8 percent in 2005, to 15 percent in 2010, and 25 percent in

³Generation mix, for example, greatly determines how generators will be affected by shocks to fuel prices.

2015. The average price that utilities paid to ISO markets tracked the changes in generation costs more closely than the contract prices. However, as with bilateral contracts, ISO prices increased more in deregulated markets over this period.

We calculate the wedge between wholesale prices and generation costs using several measures of costs. In perfectly competitive markets, market prices equal the marginal cost of producing one additional unit. We construct a measure of average marginal costs at the market level by capturing the fuel costs of the most expensive generating plants.⁴ We also consider average variable costs across all generating plants, and we construct both measures at the state level in addition to the service area level. All of these measures indicate a decline in generation costs while wholesale prices increase, generating a larger wedge for deregulated utilities.

We also establish the presence of another factor that contributed to the delayed impacts of deregulation. Despite the divestiture of generation assets, utilities maintained a high degree of vertical integration through contracts and corporate 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.⁵ In wholesale markets, we find that the use of contracts delayed the onset of effective 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 that electric deregulation in the U.S. yielded higher wholesale prices, despite declines in generation costs. The effect is most evident in substantial increases in bilateral contract prices, though we also observe increases in wholesale prices paid in ISO markets and power pools. The increase in average annual wholesale prices is a significant channel through which deregulation affected retail rates. Our estimated increase in utility energy costs can account for most of the differential trend in retail rates observed in deregulated states.

Market imperfections may explain the relative price increases for deregulated utilities over this period. One candidate explanation is the exercise of market power by deregulated generators, which can generate a wedge between costs and prices. Early on, Borenstein and Bushnell (2000) noted that “market power among generators is likely to be a more serious and ongoing

⁴In a scenario where all generating firms are price takers, low cost plants could earn margins over generation costs, as the market price is set by a more expensive generating unit. Theoretically then, a shift from average cost pricing (in regulated markets) to marginal cost pricing (in deregulated markets) could increase prices even without market imperfections. To distinguish this mechanism, we focus on the costs of the most expensive plants. We find that the generating costs for the most expensive plants are falling while wholesale prices are increasing, which implies that prices are increasing beyond marginal costs.

⁵We use the term “affiliate” as a company belonging to the same parent company.

concern than has been anticipated by most observers.” Wholesale markets have several characteristics that can limit competition and allow generators to exercise market power (Borenstein, 2002),⁶ and these did not fundamentally change with deregulation. The previous literature has documented market power in electricity markets over our sample period (e.g., Borenstein et al., 2002; Puller, 2007; Bushnell et al., 2008; Ito and Reguant, 2016).

In spot markets, market power can explain an increased wedge between wholesale prices and generation costs through profit-maximizing (strategic) bidding by generators (Hortacsu and Puller, 2008)⁷ and strategic withholding to increase prices (Mercadal, 2022). For bilateral contracts, which comprise the vast majority of wholesale purchases by utilities, market power could be an even larger concern, as there are few firms that can credibly negotiate to supply a utility with a large quantity over a long period. Market power could be exacerbated through contract requirements that are imposed by the state-level utility commission. Such requirements can limit the number of competitors and allow suppliers to charge greater markups. Consistent with the market power explanation, we find that the wedge between prices and costs increases by more in markets with less elastic demand, as measured by the share of residential consumers (who tend to be less price responsive than industrial and commercial consumers).

Other market imperfections could also contribute to an increasing gap between prices and costs in electric wholesale markets. For example, market-based generators may face additional risks, as wholesale prices are no longer guaranteed to recover costs and there have been ongoing policy changes in response to environmental uncertainty. These risks may lead investors to demand a higher return, which would be obtained through higher margins. While the policy implications of different market imperfections vary, the wedge between prices and gaps points to an inefficiency that seem to have become worse with deregulation. Despite our findings, it is important to note that regulated markets can suffer from several types of inefficiencies that can justify the introduction of markets.

We examine other potential explanations for the increasing wedge between wholesale prices and generation costs. Our empirical strategy controls for the evolution of fuel prices and the generation mix in each market. However, it is possible that differential changes to environmental regulations, wholesale spot markets, or entry of new plants differentially affected the wholesale prices in deregulated markets. First, consider environmental regulation. Despite a greater rate of renewable portfolio standards (RPS) in deregulated states, such regulations do not appear to be binding in our sample. The share of generation from renewable resources followed a similar pattern for regulated and deregulated utilities. Moreover, the share of these

⁶Both demand and supply are inelastic, yet supply must meet demand at every moment because 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.

⁷Hortacsu and Puller (2008) conclude that “firms with large stakes in the market behave close to theoretical predictions of a strategic model of oligopolistic interaction.”

sources was rather low: less than 5 percent in 2006 and less than 10 percent in 2016. Therefore, even if renewable generation is more expensive in deregulated states, it is unlikely to explain the large increase in wholesale prices that we find. Similarly, wholesale spot market purchases represented a minority of purchases electricity over our sample period, and the relative share followed a similar trend in deregulated and regulated states. Finally, entry of new capacity also followed a similar pattern across the two groups. Thus, these channels do not indicate any significant structural changes in the character of the generation markets, other than the shift from regulated cost-based prices to market prices.

The existing literature on the consequences of deregulation is surprisingly scarce, given the importance of the electricity sector for the economy and decarbonization efforts. The literature has documented gains in productive efficiency in several dimensions. Fabrizio et al. (2007) show that deregulated 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, as we also find moderate declines in fuel costs for power plants in deregulated states.

However, the existing literature on restructuring has not yet determined whether these cost reductions have translated into lower prices. 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.⁸

Borenstein and Bushnell (2015) examine the consequences of restructuring between 1998 and 2012 and argue that retail price 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

⁸Although 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 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.

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. Instead, our findings suggest that increasing margins result from imperfect markets.

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 findings 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 assessing the impact of the choice to make or buy electricity and 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. Section 5 presents our main results for wholesale markets, the implications for upstream prices, and the passthrough to retail 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. Section 7 concludes.

2 Background

2.1 Deregulation Efforts in the U.S.

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.⁹ Although the details of the deregulation process varied across industries, the principles motivating this process were the same: market competition would increase efficiency and thus reduce prices. 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, concerns remain about market power and other market frictions (Borenstein, 1989; Borenstein

⁹Market-based prices are those determined by demand and supply, as opposed to cost-based prices determined by a regulator as a function of cost.

and Rose, 1994, 2014; Viscusi et al., 2018).¹⁰

In these industries, concerns about market imperfections remain because, theoretically, market participants can raise prices even when costs decline. If markets are not perfectly competitive, firms have an incentive to raise prices above marginal costs. Both lower costs and higher prices yield greater margins, though higher prices typically yield a reduction in output. A key factor that determines the ability of market participants to raise prices is the slope of residual demand. If firms have market power and residual demand is sufficiently inelastic, prices can go up as a result of deregulation. In Appendix B, we use a simplified model to illustrate the range of possible prices and this potential tradeoff.

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 State-Level Deregulation of 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 a series of reforms in the 1990s.

We use the term *deregulation* to refer to the switch from cost-of-service regulation to market-based prices. At the state level, local politics determined the extent to which each state committed to deregulation and the use of competitive wholesale markets (Borenstein and Bushnell, 2015).¹¹ To facilitate the switch, several states passed laws that induced investor-owned utilities to divest their generation assets.¹² The goal of vertical separation was to create a competitive generation sector that would reduce costs. Prior to wholesale market deregulation, the majority of electricity came directly from vertically-integrated generators, and utilities were reimbursed for generation at regulated rates.¹³ After, utilities in deregulated states generally had

¹⁰In the past two years, the Department of Justice has sued to stop an alliance and a merger in the airline industry (one between JetBlue and American Airlines and the other between JetBlue and Spirit) on the grounds that each of these would raise prices. In the US cable industry, for example, Rubinovitz (1993) finds that over 40 percent of the price increase after deregulation was due to the exercise of market power.

¹¹Borenstein and Bushnell (2015) note that FERC technically retains the authority to regulate wholesale market rates, even if it does not exercise that authority.

¹²On average, states that passed deregulation measures had higher pre-deregulation rates than those that remained regulated, but the decision to deregulate was not necessarily 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.

¹³Competitive 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 purchase all electricity at market prices, either through long-term contracts or in centralized auctions organized by transmission operators.

In addition to the push for wholesale markets, several states also introduced alternative retail suppliers downstream. Unlike utilities, which offered retail electricity at regulated rates, alternative retail suppliers were free to set their own prices. Customers that chose alternative retail suppliers paid these prices plus regulated distribution fees to the incumbent utilities. Except for Texas and Maine, customers in these states could still buy “bundled service” from the incumbent utility, in which the electricity price was regulated to equal the utility’s average cost of production. Over our sample period, a meaningful share of industrial and commercial customers switched to competitive retailers, but, in most states, the large majority of residential consumers still purchased from the incumbent utility.¹⁴

Other restructuring measures were also implemented to help facilitate wholesale market transactions. Most notably, there was a nationwide increase in the use of centralized procurement auctions organized by independent system operators (ISOs). The ISOs were in charge of coordinating the use of transmission assets and covered six regions: 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. As we document in this paper, the share of electricity purchased via these centralized markets rose from approximately 10 percent in 2000 to 25 percent by 2016. However, states in which utilities did not divest their generation assets realized a similar increase in the share of purchased power coming from ISOs, as we show later. Thus, the state-level deregulation measures provide a distinct set of variation from the growth in these centralized markets.

Over our sample period, the majority of purchased electricity was obtained through bilateral contracts, rather than centralized markets. Thus, our analysis that incorporates bilateral contract prices helps to provide a more complete picture of the evolution of wholesale markets. In addition, as utilities pass on the procurement costs one-for-one to downstream customers on regulated rates, we are able to trace out the impact of changes to the wholesale market on retail prices. If higher retail prices occur without a corresponding increase in wholesale prices, we could instead infer that the increase in retail prices is due to other components of the customers’ bill—such as distribution costs or stranded costs—that are not related to market-based wholesale prices.¹⁵

to share transmission assets with competing generation facilities.

¹⁴See Hortaçsu et al. (2017) for a discussion of the causes of this phenomenon.

¹⁵To 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

3 Data

3.1 Dataset Construction

To measure prices and margins, 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, although the structure of the deregulated market changed, the geographical territories for distribution essentially remained unchanged, and the ultimate delivery of electricity to consumers continued 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.

Investor-owned utilities report detailed expense data on FERC Form 1. Expenses are reported for power production, transmission, regional market expenses, distribution, managing customer accounts, customer service, sales, and administrative and general items. Power production includes both the costs of own generation (including fuel costs and operations and maintenance) and the costs of purchased electricity. The deregulation measures we study affect most directly expenses related to the production of power, as they caused utilities to shift from own generation to purchased electricity. Typically, the roles of the regulated utility for these other components—e.g., transmission, distribution, maintaining customer accounts—remained unchanged following these deregulation measures.

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

measuring the effects of deregulation, which we address in Section 6.

by a utility come from the same parent company versus independent suppliers.¹⁶ The data on ownership structure was manually constructed from a combination of sources, including 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.

During the period of analysis, 21 states passed laws to promote market-based prices at the wholesale level or retail level.¹⁷ Typically, this was accomplished through the vertical separation of utilities and generators upstream and the introduction of alternative retail suppliers (and retail choice) downstream. Though we view these as common first-order changes, details varied from state-to-state. We address heterogeneity across affected states by reporting some key results separately for each state.¹⁸ We remove several states from the sample because of their idiosyncratic regulatory contexts. Four states—Arizona, Arkansas, Nevada, and Montana—initially passed restructuring measures but later rescinded them. Michigan only implemented deregulation measures in retail markets but retained a vertically integrated market upstream. Nebraska and Tennessee did not have investor-owned utilities with generation resources, they are not included in the sample. We also remove Hawaii and Alaska, as the electricity infrastructure in these states is quite different from the rest of the United States. Thus, our sample of utilities covers 16 states that deregulated 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 Some investor-owned utilities have service areas across multiple states. In these cases, we divide utilities at state borders and treat them 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.

¹⁶We 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).

¹⁷Our sample of states that passed deregulation measures includes Rhode Island, New York, California, New Hampshire, Massachusetts, Pennsylvania, New Jersey, Delaware, Maryland, Connecticut, Illinois, Maine, Ohio, Texas, Virginia, and Oregon.

¹⁸See Table A2 in the Appendix.

¹⁹In 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.

We focus on service areas because, even in deregulated markets without retail service, utilities continued to own and operate distribution lines and provide delivery service to retail customers. The geography of service areas and the corresponding distribution infrastructure was quite stable over time.²⁰ We 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 beginning of our sample. Our final sample consists of 147 merged IOUs that provided approximately 70 percent of generation and 70 percent of retail service in 1994.

Key outcomes of interest include wholesale prices and generation costs. 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. We combine these data with the average fuel cost of own generation for vertically-integrated utilities to construct a measure of the average variable cost of electricity to the utility (either generated or purchased), which we call the *utility cost*.

For generation costs, we compute plant-specific fuel costs using net generation, fuel consumption, and fuel prices from EIA data. We obtain generator efficiency by dividing fuel consumption by net generation, and we multiply this by the average unit price of the fuel to obtain per-MWh fuel costs. We assume the unit price for fuel is equal to the average unit price for each fuel type in each state and year. This approach allows us to account for idiosyncratic differences across plants and over time in efficiency and fuel types. We construct average fuel unit prices in each state and year for each of the 27 EIA fuel types (e.g., Bituminous Coal, Lignite Coal, Sub-bituminous Coal) using utility-reported fuel receipts. When fuel receipts are not available for a given type-state-year, we impute with flexible regressions with nonparametric trends for each type-year and type-state within each high-level fuel group (e.g., Coal).²¹ For nuclear plants, we use the national weighted-average purchased price of uranium provided by EIA to construct unit prices.

We then use the generator-specific fuel costs (per MWh) to construct a measure of annual marginal costs. For each utility in each year, 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 reflects the marginal cost at the market level,

²⁰For a visual representation of the geographic coverage of these areas, see Figure A1 in the Appendix.

²¹Due to reporting requirements, the data on fuel receipts in deregulated states comes disproportionately from smaller municipal utilities and co-ops, which typically have higher procurement costs than the larger generation companies. Thus, our fuel price measure can be interpreted as an upper bound. As we will see in the next section, our findings would only change if fuel prices for deregulated generators rose much faster relative to those for municipalities and co-ops, which we think is unlikely. This reporting issue only pertains to fuel receipts, not fuel consumption or net generation.

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

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 under least-cost dispatch, and their costs would determine prices in perfectly competitive markets. Thus, margins over this measure of marginal cost reflect market power or other market imperfections, and not competitive rents for inframarginal plants. 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. Thus, to be consistent with our annual data, our measure reflects the cost of a 1 MWh increase in generation averaged across different points within a year.²³ Fuel would be the primary component of a marginal increase in production.

Our results are not sensitive to the lower-end percentile used in this calculation; we obtain similar results if we use the 60th-100th or 90th-100th percentiles instead. With the 75th-100th percentile, marginal costs are close 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 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 compute retail margins (retail price minus wholesale price), wholesale margins (wholesale price minus marginal cost), and gross margins (retail prices minus generation costs) using these measures. For some analyses, we also consider average variable fuel costs across all generation units, which allows us to calculate profits/rents.

Besides generation costs, we look at total production costs by utilities, which we obtain from FERC Form 1. This includes operations and maintenance (O&M) costs related to the generation of energy in addition to the fuel costs of generation and the costs of purchasing energy from external generators. Without substantive changes in O&M expenses, the trends in this additional measure should track the trends in our measure of utility costs.

We also examine retail prices to determine the extent to which retail prices have followed wholesale prices. For our primary measure of retail price, we use the average bundled price offered by utilities to residential, industrial, and commercial customers. We construct this measure by taking the average price for bundled service for each customer type and weighting

²³A more precise measure would leverage data that identifies the marginal unit producing at every hour in every market and construct the weighted average of fuel costs across these marginal units. Previous papers have used data on hourly production costs when analyzing centralized wholesale markets. However, in our setting, most energy is traded through long-term contracts and not hourly transactions, and thus annual costs are perhaps a more appropriate measure.

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)	15.24	15.22	0.960	15.49	0.643
ln(MWh Generated)	14.74	14.60	0.817	14.59	0.859
Marginal Generation Share: Coal	0.41	0.54	0.294	0.44	0.832
Marginal Generation Share: Gas	0.22	0.15	0.513	0.24	0.944
Marginal Generation Share: Nuclear	0.00	0.03	0.399	0.00	0.293
Marginal Generation Share: Oil	0.21	0.07	0.057	0.17	0.730
Marginal Generation Share: Water	0.15	0.20	0.569	0.15	0.976
Marginal Fuel Costs	69.19	37.52	0.101	64.15	0.851
Retail Price	80.64	58.95	0.001	59.32	0.001
Number of Unique Utilities	71	76		66	

Notes: Table displays 1994 characteristics for 71 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.

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.²⁴

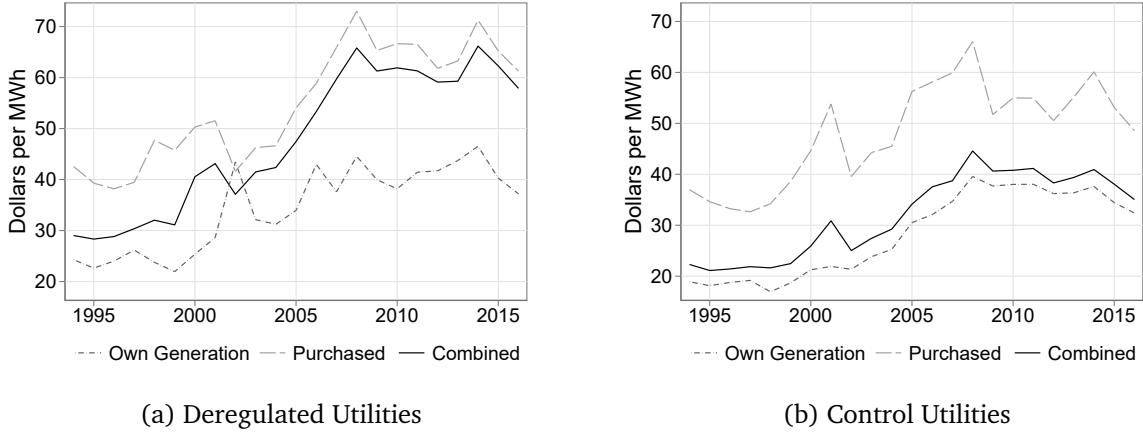
3.3 Summary Statistics

In this section, we provide some summary statistics of key variables in our sample. We identify similarities and differences between utilities in deregulated states and those in control 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 71 IOUs in the deregulated states, and column (2) reports the mean across the 76 IOUs in the control states. Overall, utilities in these two groups 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 (0.21 versus 0.07). This

²⁴Throughout, 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).

Figure 1: Average Production Costs for Utilities



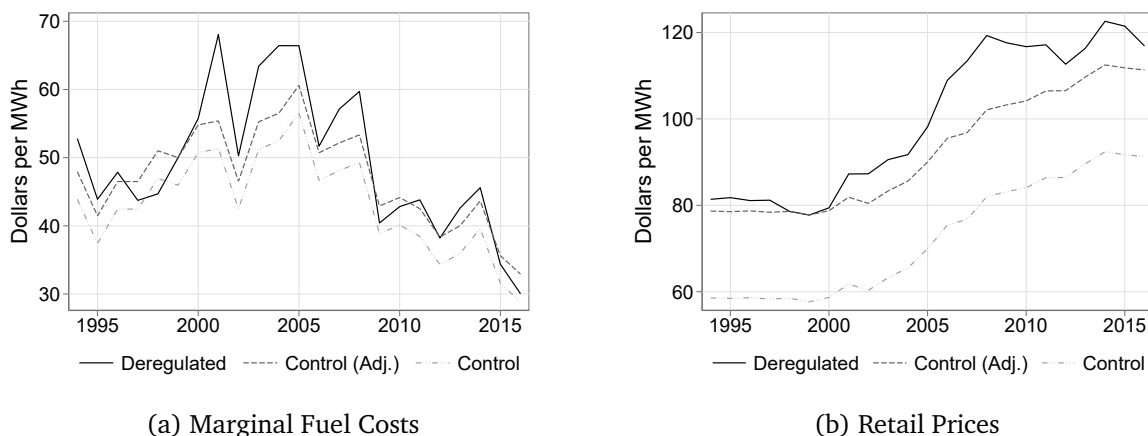
Notes: The figure reports the average production costs for deregulated utilities (panel (a)) and control utilities (panel (b)) based on FERC Form 1. The dashed-dotted line reports the average expense per MWh for own generation, including operation and maintenance. The dashed line is the average price of purchased power. The solid black line reflects the average production cost across own generation and purchased power. The weights for each time series are the MWh serviced by each utility. The black line is not simply a weighted average of the other two lines.

gives rise to a difference in marginal fuel costs, which are substantially larger in deregulated states in 1994. Despite these mean differences, the p-values of the difference in means for these variables, which are reported in column (3), are greater than 0.05, indicating a good deal of heterogeneity among utilities within each group.

These two 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 4.1.

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 0.14 to 0.04. Marginal fuel costs for the matched control group increase to 64.2 dollars per MWh, which is close to the mean of 69.2 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 0.464 in column (3) to 0.766 in column (5). Note that the matching procedure only selects 66 out of the 76 possible control utilities as nearest neighbors.

Figure 2: Average Generation Costs and Retail Prices



Notes: Panel (a) plots the average marginal 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). Panel (b) plots the quantity-weighted retail price for investor-owned utilities in deregulated states and in control states. The dashed line in both panels plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

Overall, utilities in deregulated states had higher prices than similar utilities in control states. These differences primarily reflect costs unrelated to the production of power (e.g., transmission and retailing costs). To show this, we report production costs for deregulated utilities and control utilities in Figure 1. The solid line reflects the average cost of production reported from FERC Form 1, which includes purchased electricity and the total costs of own generation. On average, these costs are between 20 and 30 dollars per MWh from 1994 to 1999, substantially less than retail prices.

Figure 1 also points to key changes to the upstream market after deregulation. The dash-dotted line shows that the average cost of own generation (including operation and maintenance of the generating plants) evolved similarly in deregulated in control states, rising from roughly 20 dollars per MWh to roughly 40 dollars per MWh by the end of our sample. However, the average price of purchased power, as shown by the light dashed line, increased by more in deregulated states after 2006. This increase corresponds to an increase in wholesale market prices.

Moreover, a greater share of power production for deregulated utilities shifted to purchased electricity as they divested generation assets. This caused the average cost of production to shift closer to the (higher) cost of purchased power, while the average cost of production in control states remained slightly above the average cost of own generation. These two findings: that wholesale prices increased and average production costs increase, are key to understanding the evolution of the market after deregulation. In Section 4 we analyze in depth the role of deregulation in the observed rise of utility costs, as well as its implications for retail rates.

One possibility for the increase in wholesale prices is that deregulated utilities realized

greater increases in fuel costs. In Figure 2, we present the time series of marginal fuel costs for the two groups. Fuel costs for generation facilities in deregulated markets closely tracked fuel costs in control markets from 1994 through 2000. From 2001 to 2005, fuel cost increased in deregulated markets. However, starting in 2005, generation costs began to decline, and they declined more rapidly in deregulated markets.

The general patterns we observe are not sensitive to the particular measure of costs. In Figure A11 of the Appendix, we show similar trends using average variable fuel costs rather than our measure of marginal costs. In Figure A12 of the Appendix, we present trends in costs using statewide measures of marginal and average variable fuel costs, rather than utility-specific measures. As in panel (a) of Figure 2, we find declining costs in both deregulated and control states in the latter half of our sample.²⁵

Thus, wholesale prices rose in deregulated states relative to control states (Figure 1) without a corresponding rise in fuel costs in these states. Instead, fuel costs in deregulated markets declined overall. This high-level finding is consistent with an increasing wedge between wholesale costs and prices in deregulated states relative to control states, and motivates our more in-depth empirical analysis in Section 4.

Finally, we consider the implications of higher wholesale prices for consumers. In panel (b) of Figure 2, we present the time series of average retail prices. The figure 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, and from then on the gap between the two widened further. The gap between deregulated and control markets in retail rates more closely corresponds to changes observed in wholesale prices, rather than generation costs. To the extent that utilities pass through increases in production cost to downstream consumers, part of the increase in retail rates can be attributed to the changes in the upstream wholesale markets.

4 Empirical Strategy

The goal of our analysis is to evaluate the effect of electricity restructuring on wholesale margins and prices. For this, we compare utilities in deregulated 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 below.

²⁵Using 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.

By individually matching utilities based on their size and generation mix 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 for some relevant geographical variation, because plants in different locations may face different fuel costs.²⁶ Intuitively, we are using the data to provide an answer to the question, “What happened for similar utilities in states that did not restructure?”

A state’s decision to restructure its electricity sector was not completely random. 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 restructuring. Though comparable utilities in states that implemented deregulation measures initially had higher retail prices (Table 1), margins were similar, and costs and prices follow similar trends from 1994 through 1999 (Figure 2). This suggests that the parallel trends assumption may be reasonable before the onset of restructuring.

Second, the parallel trends assumption requires that shocks unrelated to restructuring 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 because the effect of these shocks depends primarily on the generation mix. We discuss this and other alternative mechanisms in more detail in Section 5.3.

Third, the assumption requires that the effects of restructuring did not spill over into control states. Because of the ongoing integration of electricity markets across states, it is plausible that restructuring 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 restructuring, as wholesale prices also increase in control states (Figure 1). Thus, it may be possible that market dynamics in the deregulated states could drive up wholesale prices in the states that remained regulated.

A final consideration is whether other aspects of markets that affected market power, margins, and cost efficiency developed differently following deregulation. For example, we expect entry decisions to follow different dynamics in deregulated 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.

²⁶For 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.

4.1 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, generation technology, and marginal fuel 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 these matched groups to control for nonparametric trends in the data, 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 71 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 match on log generation MWh, log retail MWh, marginal costs,²⁷ and the shares of (marginal) generated MWh coming from five fuel types: 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 control group outcomes and employ standard difference-in-differences techniques to adjust for pre-period differences. Let Y_{it} denote an outcome of interest (e.g., wholesale 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 $\hat{Y}_{it}(0)$ indicate estimated outcomes without deregulation. Given $Y_{it}(1)$ and $\hat{Y}_{it}(0)$, we can obtain a utility-specific estimate of the effect of deregulation on the outcome, $\widehat{\Delta Y}_{it}$:

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

We observe the outcome $Y_{it}(1)$ for the deregulated utilities in our data. The outcome $\hat{Y}_{it}(0)$ is unobserved and is calculated as follows. For each deregulated utility i , we select three nearest neighbors using the above procedure. We calculate the unobserved outcome, $\hat{Y}_{it}(0)$, as the average value of $Y_{it}(0)$ across the three matched control utilities plus the difference between

²⁷When matching, we transform marginal costs using the inverse hyperbolic sine, $f(z) = \ln(z + \sqrt{1 + z^2})$, which is approximately the natural log function plus 0.7 for $z > 5$ and also has $f(0) = 0$.

²⁸Specifically, 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 generation mix. We match over three-quarters of the utilities almost exactly based on fuel types.

deregulated and matched control outcomes in the period prior to deregulation. Thus, outcomes are indexed so that $Y_{i0}(1) = \hat{Y}_{i0}(0)$. By indexing the levels to a baseline period, equation (1) obtains 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:

$$\hat{\tau}_t = \frac{\sum_i \omega_i \hat{\tau}_{it}}{\sum_i \omega_i}. \quad (2)$$

where ω_i is the retail MWh serviced 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.

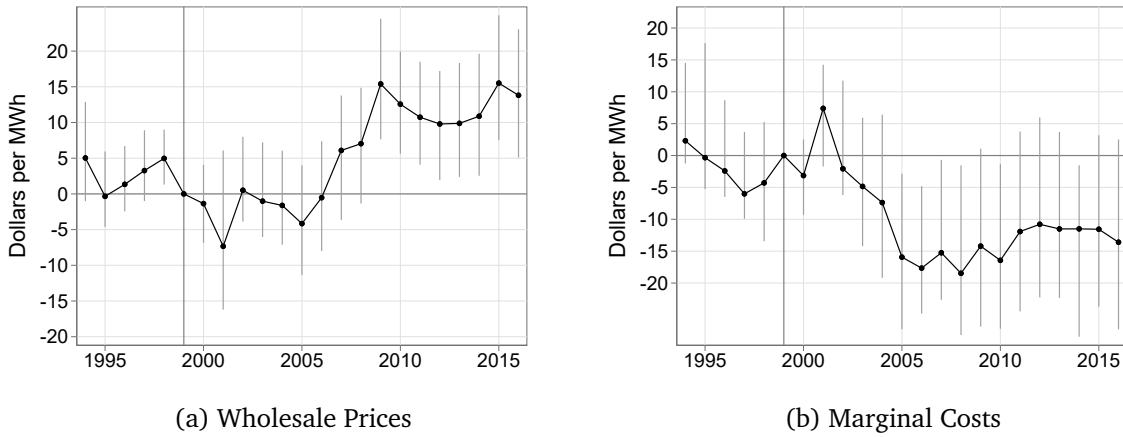
For our main analysis, we use 1999 as our baseline period across all states. Though there is some variation in terms of when deregulation measures legally came into effect across states, in practice, the restructuring effects all happened within a few years. This timing has little impact on the results 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 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, $\hat{\theta}$. 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 $\hat{\theta}_b$. The matching estimator converges at rate $\sqrt{N_1}$ (Abadie and Imbens, 2006, 2011), and the estimated CDF of $\hat{\theta}$ is given by:

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

The lower and upper bounds of the confidence intervals can then be estimated as $\hat{F}^{-1}(0.025)$ and $\hat{F}^{-1}(0.975)$. We employ $R = 3$ ($B_1 = 25$) for the confidence intervals and standard errors reported in the paper.

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



Notes: Figure displays difference-in-differences matching estimates of changes in (a) wholesale 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.

5 Measuring the Effects of Restructuring Electricity Markets

5.1 Wholesale Market

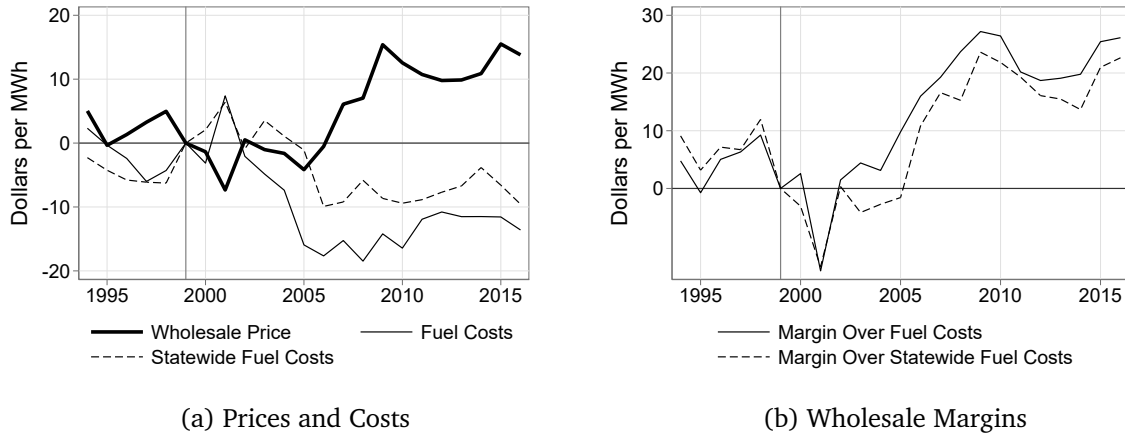
We start by showing that wholesale prices increased in deregulated relative to control states. Panel (a) of Figure 3 displays the average change in wholesale prices relative to matched control utilities. Leading up to the baseline year of 1999, there is little difference in price trends for deregulated and control utilities. From 2000 to 2006, the first years after restructuring started, wholesale prices remained at similar levels for the two groups. In 2007 and 2008, prices slightly increased in deregulated markets. Later in 2009, wholesale prices paid by deregulated utilities rose sharply, and remained higher than in control states until the end of our sample in 2016. Between 2008 and 2016, we estimate that wholesale prices were 11.8 dollars per MWh higher in deregulated states. The average wholesale price paid by deregulated utilities in 1999 was 42.3 dollars per MWh; an increase of 11.8 dollars per MWh corresponds to a 28 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

²⁹For a comparison, see Figures A9 and A10 in the Appendix.

³⁰Matching 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: Estimates of Changes in Prices, Costs, and Wholesale Margins



Notes: Figure displays difference-in-differences matching estimates of changes in prices, costs, and wholesale margins for deregulated utilities. Panel (a) provides the point estimates for wholesale prices paid by utilities (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 wholesale margins, which are defined as the wholesale price minus fuel costs, using both measures of costs from panel (a).

period. From 2000 to 2016, marginal costs declined by 10.5 dollars per MWh in the deregulated utilities. Thus, despite declining costs, wholesale prices significantly rose in deregulated states.

The combined effects of increasing prices and decreasing costs suggest that margins over costs paid by utilities in the wholesale market rose in deregulated states. To illustrate this, we combine the wholesale price effects and the generation costs on the same plot in panel (a) of Figure 4. The difference between the wholesale price (in thick solid black) and the fuel costs (in thin solid black) is the wedge paid by utilities above the generation costs of electricity. The wholesale margins are plotted in panel (b). They were relatively flat from 2000 to 2005, a period of retail rate freezes and corresponding low wholesale prices. In 2006, price-cost wedges spiked, rising to over 10 dollars per MWh every year from 2006 through 2016.

Our finding of increasing price to cost margins 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 wholesale margin using

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Generation Cost (MC)	Wholesale Margin	Wholesale Price	Retail Margin	Retail Price	Gross Margin	Utility Cost
1999 Values	49.92	-6.61	42.26	35.99	78.57	28.60	33.55
2000-2007	-7.36 (3.32)	5.18 (4.37)	-1.23 (3.15)	6.60 (2.87)	5.74 (1.98)	13.03 (4.23)	4.86 (2.35)
2008-2016	-13.29 (6.27)	22.90 (7.05)	11.76 (3.46)	2.90 (3.40)	11.54 (2.97)	24.85 (7.03)	14.36 (3.27)
2000-2016	-10.46 (4.28)	14.19 (4.94)	5.53 (2.99)	4.44 (2.69)	8.81 (2.25)	19.20 (4.98)	9.59 (2.42)

Notes: Table displays the estimated difference-in-differences matching coefficients for prices, costs, and margins 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.

this alternative measure of costs. We still find large increases in the wedge between wholesale prices and costs paid by utilities using 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 increases in wholesale prices, utility costs (average cost of generated and purchased electricity), and the wedge between the two that we observe are economically meaningful and statistically significant in the second half of our sample. We tend to observe larger effects for all variables starting around 2008, several years after the deregulation measures were initially passed. Section 6 presents a discussion of how long-term contracts and rate freezes delayed the effects of deregulation, rationalizing the timing of the observed changes in prices and margins.

In Table 2, we also present an estimate of impacts to retail prices. Consistent with upstream energy costs being passed through to downstream consumers, the overall estimate for retail prices (8.8 dollars per MWh) is similar to the estimated increase in utility energy costs (9.6 dollars per MWh). Thus, the changes we observe in the upstream market are comparable in magnitude to the differential trends in retail prices in deregulated states.

Robustness Checks Our findings are similar if we index each utility to state-specific implementation dates, rather than calendar time. Figure A9 in the Appendix shows that the share of own generation divested looks nearly identical using both measures of time. Figure A10 in the Appendix plots the corresponding effects on prices and costs, which are similar to the estimates in Figure 3 above.

As an additional robustness check, we estimate an alternative version of our matching pro-

³¹The changes in margins 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 margins.

cedure 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 on region 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.

Section C in the Appendix discusses the variation in these effects across states. We estimate some heterogeneity across states. Most deregulated states realized meaningful upstream price increases. For 11 out of 16 states, utility costs went up by amounts greater than 3 percent of the retail price. We estimate that only Connecticut had a meaningful decline in utility costs.

5.2 Retail Market: Utility Energy Costs and Regulated Rates

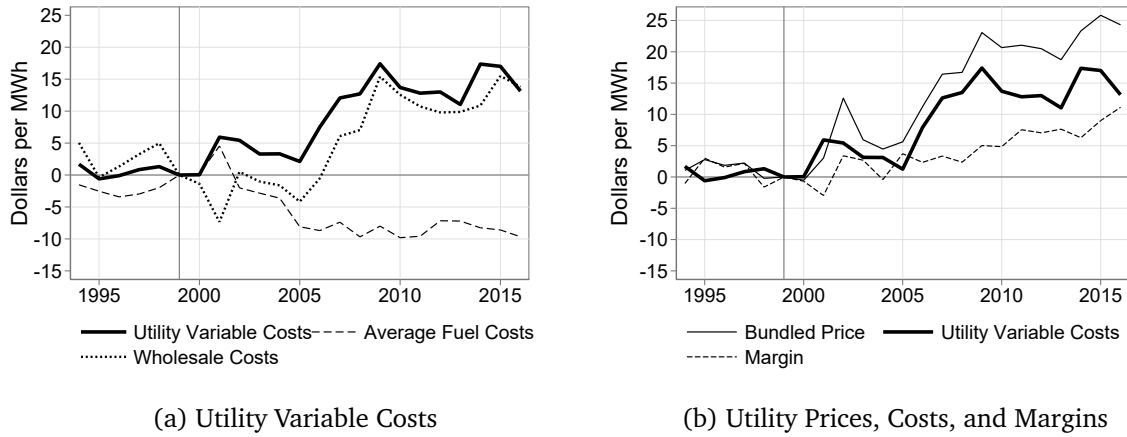
Our findings that wholesale prices and margins increased after restructuring imply that utilities faced higher prices to procure energy for their retail customers. In this section we focus on incumbent utilities. In most states, even after deregulation, these utilities were required to continue to offer “bundled” service—i.e., providing retail electric service in addition to distribution—at regulated prices based on the supply costs (generated and purchased) of electricity. At the same time, incumbent utilities were required to switch from own generation to wholesale market purchases to supply these consumers. In what follows, we study how costs and prices moved for incumbent utilities and show that upstream changes can explain a significant portion of the increase in retail rates in deregulated electricity markets.

Panel (a) of Figure 5 shows the impact of deregulation on the energy costs for utilities using our difference-in-difference matching approach. Utility costs (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. This measure captures the average variable cost of electricity to the utility and is constructed as the weighted average of the average fuel cost of generation (thin dashed line) and the average cost of electricity purchased from wholesale markets (dotted line).

Two factors contribute to the increase in utility 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 margin over marginal cost. In 1999, the mean wholesale margin over average variable fuel costs was 15.4 dollars per MWh (see Table A4 in the Appendix). Thus, despite the fact that wholesale prices and fuel costs both *declined* over the period 2000 to 2007, utility variable costs *increased* by 4.9 dollars per MWh. With deregulation, utilities effectively paid a market premium, or margin, to generation facilities that they had previously owned.

The second factor that led to an increase in utility costs was the increase in wholesale prices beginning around 2007. Though wholesale prices remained relatively flat in the initial years of

Figure 5: Estimates of Changes in Utility Costs and Margins



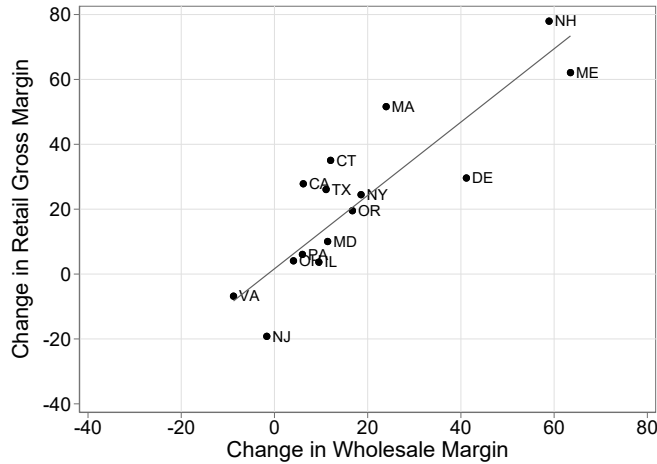
Notes: Figure displays difference-in-differences matching estimates of changes in costs, prices, and margins for regulated electric service in deregulated states. The thick black line in both panels shows the change in utility costs. Utility costs are calculated as the weighted average of generation 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 (thin solid line) and the utility margin (dashed line), defined as the bundled price minus the utility cost.

deregulation, they eventually increased substantially, rising by almost 12 dollars per MWh from 2008 to 2016. The increase in wholesale prices, combined with the significant declines in fuel costs, indicate that wholesale margins for generators increased substantially in deregulated states. Our difference-in-differences estimate for the increase in wholesale margins is 14.2 dollars per MWh from 2000 to 2016.

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 utility costs (thick solid line) explains most of the increase in regulated bundled prices (thin solid line). Utility margins—the difference between the bundled price and the variable costs, moved similarly in deregulated and control states until 2008, as shown by the dashed line in the figure. After 2008, there is a slight trend upward in the unexplained portion of retail prices. This could arise from components that make up utility “margins”—i.e., additional charges to cover higher distribution costs, stranded costs payments, or other features. Overall, we find that the higher retail rates primarily reflect higher energy costs for utilities. As shown in Table 2, The increase in wholesale margins is more than 70 percent of the increase in gross margins (the difference between retail prices and fuel costs), and the increase in retail rates is comparable to the overall increase in utility costs.

The changes documented in Figure 5 point to the role of two fundamental economic mech-

Figure 6: Margin Passthrough By State



Notes: Figure displays the correlation between the average diff-in-diff estimated change in wholesale margins and the average estimated change in retail gross margins, the difference between retail prices and marginal costs. We find significant correlation between these two measures, which suggests rising wholesale margins were a significant factor behind the observed increased in retail prices.

anisms in explaining retail price increases in deregulated states. First, the divestiture of generation facilities allowed generators to charge margins to downstream utilities, which were initially producing most of the energy sold. 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 wholesale margins did not increase, but margins were applied to a much larger share of generated electricity. Over this period, retail margins for incumbent utilities remained roughly constant.

The second mechanism was an increase in the margins charged by generators, which corresponds to the rise in 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.

In Figure 6, we plot the state-level diff-in-diff estimates of changes in retail gross margins, which are the difference between retail prices and marginal costs, against changes in wholesale margins realized by generators. The points reflect the average changes over the period 2000–2016. An increase in either margin can reflect an increase in price, a decline in marginal cost, or both. The states with the largest increases in margins—Maine and New Hampshire—realized significant declines in marginal costs when they shifted away from expensive oil plants after deregulation. We find a strong correlation ($0.86, p < 0.01$) between the effect of deregulation on these two margins. In states where wholesale margins rose more, we also find a larger increase in retail gross margins. The slope on a linear fit, which is plotted for reference, is 1.08. This correlation suggests that rising wholesale margins may be an important mechanism

behind higher retail rates in deregulated markets.

5.3 Discussion

We have shown so far that restructuring lead to higher wholesale prices and lower costs. The finding that wholesale prices increased while costs remained constant or decreased, and thus that the wedge between them went up, indicates that firms were increasingly able to set price above marginal cost. The most natural explanation for this is limited competition and market power, but we consider other market imperfections and complementary mechanisms that could have contributed to the larger margins.

At an annual level, we find substantial margin increases over the costs of the most expensive power plants. Thus, our findings suggest that market power may be a broad phenomenon. Even if wholesale spot markets organized by ISOs are fairly competitive, our data indicate that most power is sold via contracts at a margin over generation costs. Bilateral contracts are sometimes negotiated with a small set of qualified suppliers (e.g., due a requirement for renewable energy), which could reduce potential competition for a contract and increase margins. Understanding the source of these increased margins is therefore key in order to design effective policies that promote competition in deregulated markets.

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.

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 margins of around 100 percent (Borenstein et al., 2002; Borenstein, 2002). For prices to fall, substantial efficiency gains would be required to compensate for margins of this magnitude.

Further, since the California energy crisis, restructuring measures changed the balance of market power between buyers and sellers. For instance, the introduction of retail competition could allow generators to charge larger margins, as a greater number of buyers in the wholesale market can increase the relative bargaining power of generators. Section D in the Appendix documents that concentration among buyers has decreased in deregulated markets, while concentration among sellers has remained constant. Even if concentration is not the ideal measure of market power in these markets, these shifts are at least consistent with greater bargaining power for generators.

Although nationwide restructuring measures facilitated the exchange of electricity across geographic markets, local deregulation did not do much to increase within-market competition. Utilities tended to sell off their entire portfolio of generation to a single new entity.³² 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.

Consistent with market power as a significant driver of the higher margins, we find that both retail gross margins and wholesale margins increased more in markets with a more inelastic demand. Although we do not observe demand directly, demand is likely less elastic in markets with a higher share of residential customers or a lower share of industrial customers. We present analyses building on this intuition in Section D in the appendix.

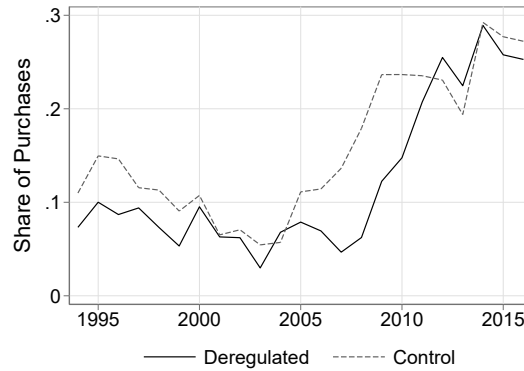
In a perfectly competitive market, we would expect increasing margins to attract new entrants. However, Figure A5 in the Appendix shows that entry has been limited, with net entry remaining below 2 percent of capacity after 2004, when wholesale margins were rising. It is also very similar for deregulated and control states. Thus, we do not have strong evidence that higher margins have attracted entry.³³

Other Market Imperfections In addition to limited competition, other market imperfections are likely contributors to the increasing difference between price and marginal cost in wholesale electricity markets. It is plausible, for example, that investors demand a high premium to compensate the different risks present in electricity markets, where time horizons are long and regulatory and technological shocks can dramatically change market conditions. Additionally, in deregulated markets there is no planning of the optimal portfolio of technologies to serve a given market, which creates space for coordination failures that increase risk and cost. Risk exposure is very different for a power plant owner in a deregulated market or the owner of a vertically integrated and regulated utility, and this difference has the potential to result in different levels of investment, power plant portfolios, and risk premia. More research on these topics is needed to fully understand the extent to which these channels might have contributed to the observed rise in margins.

³²“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).

³³This suggests there are significant entry barriers, which include large investment costs for new generators, long lead times for construction, the need for new transmission connections, the fact that incumbents already have plants in the best locations, and time lags for regulatory approval ranging from 8 to 14 months (Kwoka, 2008a). Further, unlike many other capital investments, investments in new generation plants are almost entirely sunk, as the 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.

Figure 7: 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.

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).

We think it is unlikely that the opening of the centrally dispatched electricity markets is driving our estimated increase in margins. First, ISO markets are not exclusive to deregulated states. For instance, of the 11 states that belonged to MISO (the second-largest ISO) prior to 2013, only one state—Illinois—implemented upstream deregulation.³⁴ Figure 7 plots the share of purchased power coming from ISO markets and power pools, which were the predecessors to ISOs. The figure shows that the share of purchased electricity from ISOs was roughly similar across deregulated and control states. Because our analysis compares utilities across these regimes, we think that it is unlikely that the observed difference in market power would come from ISO purchases.

Further, across the entire sample, the vast majority of all purchased power was through traditional bilateral contracts—not ISOs.³⁵ Deregulated states realized a relative increase in bilateral contract prices, as shown in Figure A14 in the Appendix. Though the trends in prices are different across the mechanisms, the figure also indicates that ISO market prices also increased for deregulated states, by roughly 10 dollars per MWh.

³⁴Michigan passed only downstream deregulation measures, and Montana initially passed but later rescinded deregulation measures.

³⁵If we also account for own generation, the share from ISOs is even smaller. The share from own generation is larger in control states.

Renewable Portfolio Standards and Environmental Regulation Many states pursued changes to environmental regulation since the beginning of restructuring. Most of these measures targeted retail markets (e.g., energy efficiency programs, net metering for rooftop solar). An exception were renewable portfolio standards (RPS), which required utilities to procure a minimum share of electricity from renewable sources. RPS could have increased prices (Greenstone and Nath, 2021) and might have contributed to increase utilities' costs. 25 states had passed regulation with this kind of requirement by 2007.

We think that RPS are not likely to explain the sharp rise in wholesale prices and margins that we find in deregulated states. RPS adoption occurred in both deregulated and regulated states, and the share of generation coming from renewable sources was similar across the two groups over our sample period. Moreover, even if the cost of renewable energy were higher in deregulated states, the share of energy from RPS-targeted renewable sources was rather low: less than 5 percent of generation before 2013, and less than 10 percent by 2016. Our measure of marginal costs does not typically reflect the costs of these renewables as these sources are not generally in the upper quartile of fuel costs for a given utility. For further discussion, see Appendix E.2.

Other Cost Shocks Another question is whether utilities respond differentially to shocks, such as changes in fuel prices and environmental regulations. How these shocks affected a utility's cost structure depends on the utility's initial generation mix because, for instance, more stringent environmental regulation will have a stronger effect on costs for utilities that rely more heavily on coal to produce electricity.

Our matching approach allows us to mitigate this concern to some degree, as each utility in a deregulated state is compared to utilities in control states with a similar generation mix in 1994. We do not necessarily want to control for changes in generation mix (e.g., 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 gas plants that could take advantage of the cheaper natural gas, this is something that we might want to attribute to our estimates of cost efficiencies. In our data, we observe similar trends in aggregate generation by fuel types across the two groups.

We also assess whether deregulation transition charges, which were additional charges imposed on customers to compensate utilities for the "stranded" costs of their assets, could explain the changes we observe. These charges were applied to retail rates, and would likely be second-order with respect to the changes in upstream prices we estimate. Nonetheless, we collected information on transition charges, and found that utilities began phasing them out starting around 2006. Overall, coinciding with the time we observe effective deregulation and large margin increases, we observe declines in stranded costs and transition charges. Although it is still possible that stranded costs could have led to higher retail rates for some particular utilities,

the trends in stranded costs move in the opposite direction from the price changes we observe.

For additional details, including a discussion of emissions compliance strategies and our data on transition charges, see Appendix E.2.

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

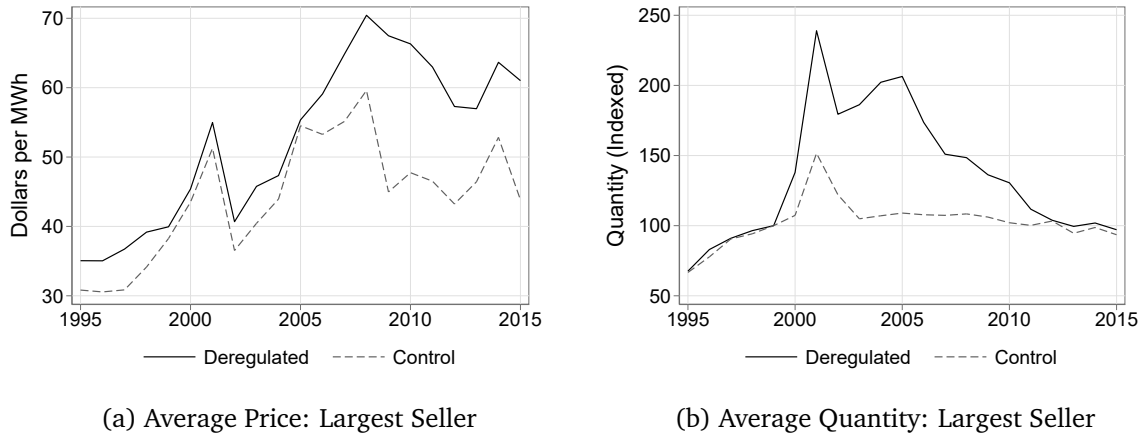
When deregulation measures were passed, most states imposed rate freezes or rate caps to guarantee low prices for consumers during the initial post-deregulation adjustment period. At the same time, utilities were vertically separated and signed long-term contracts with generators. The rates of these 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 were capped, so utilities could not pay more without incurring in losses. This situation changed around 2005, when both rate caps and contracts expired.³⁶ Two changes decreased utilities' bargaining position. First, utilities could pay more because they were allowed to increase rates if costs increased. Second, generators could sell to other buyers besides the utility, as wholesale centralized markets were starting to pick up (see Figure 7) and retail electricity providers had gained some market share.³⁷

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 8 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

³⁶See 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, Massachusetts' 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.

³⁷Section D.3 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.

Figure 8: Contract Purchases



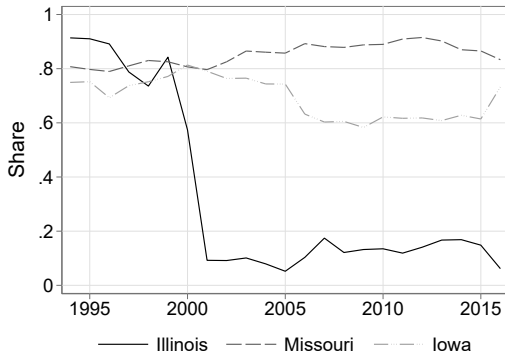
Notes: Figure plots mean characteristics for the largest buyer-seller relationships for each utility. We identify the largest seller to each utility by looking at aggregate MWh transacted for each seller-utility pair in each year. Panel (a) of the figure displays the average price paid to the largest 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).

groups moved roughly together, with utilities in deregulated states paying only slightly more for energy. After 2005, the two series diverge, increasing substantially more in deregulated 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 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 utilities signing large contracts at low prices around 2000. Starting around 2005, these contracts expired and were replaced by more expensive ones.

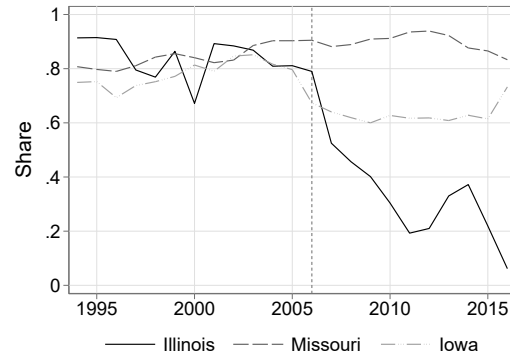
6.2 A Case Study of Delayed Effective Deregulation: Illinois

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.

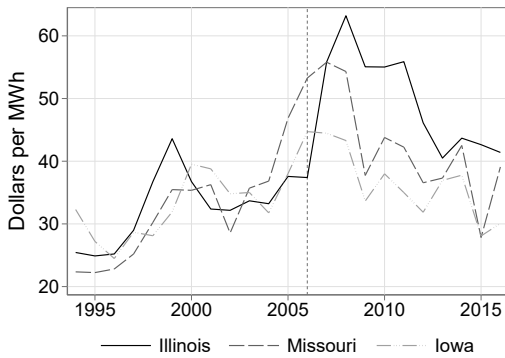
Figure 9: Timing of Deregulation: Illinois



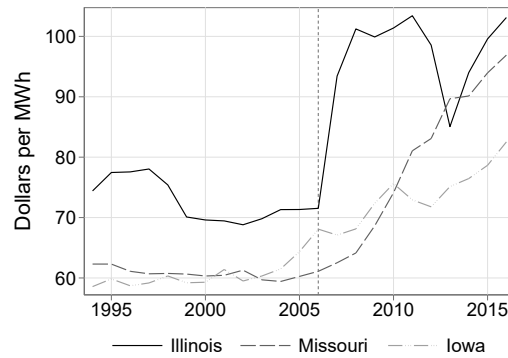
(a) Share of Electricity from Own Generation



(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.

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 9. 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 9 plots the share of own generation for Missouri utilities in a dashed line and for Iowa utilities in a dash-dot line. Although 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 9 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 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 9. 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 control utilities.

Panel (d) of Figure 9 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.

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 corporate ownership) to maintain a strong degree of vertical integration even when legal entities are vertical separated. In Illinois, wholesale and retail prices increased significantly around the time of effective deregulation. Changes to market structure due to restructuring took some time to realize in general, as shown in Section E.1 in the Appendix.

7 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 faced significantly higher costs of energy. This resulted from both higher wholesale prices as well as purchasing a higher share of energy, instead of generating it. We find that restructuring lead to sharp increases in wholesale prices despite reductions in marginal fuel costs, such that generation facilities were able to charge prices at substantial margins above costs. We show that this can explain a large portion of the increase in retail rates after the restructuring of the electricity sector.

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

Finally, our finding of increasing gaps of prices over costs may point to the need of a more sophisticated market design instead of one that relies primarily on a per-unit price. Margins indicate inefficiency because units valued in more than what they cost are not produced and consumed. However, this does not necessarily imply that the solution should be to increase antitrust efforts to reduce firms' market power. Since this is a market with large entry and fixed costs, a margin over marginal cost may be the second best in the absence of additional price components to compensate firms for their investment. Therefore, a market could be more efficient with a market design that includes an explicit fixed payment like capacity payments in the spot market or defined in the contract. This would allow prices to go down, closer to marginal cost, since firms would be able to recover their investment through fixed payments.

References

- ABADIE, A. AND G. W. IMBENS (2006): “Large Sample Properties of Matching Estimators for Average Treatment Effects,” *Econometrica*, 74, 235–267.
- ABADIE, A. AND G. W. IMBENS (2008): “On the Failure of the Bootstrap for Matching Estimators,” *Econometrica*, 76, 1537–1557.
- ABADIE, A. AND G. W. IMBENS (2011): “Bias-Corrected Matching Estimators for Average Treatment Effects,” *Journal of Business & Economic Statistics*, 29, 1–11.
- BERTRAM, G. AND D. TWADDLE (2005): “Price-Cost Margins and Profit Rates in New Zealand Electricity Distribution Networks Since 1994: The Cost of Light Handed Regulation,” *Journal of Regulatory Economics*, 27, 281–308.
- BORENSTEIN, S. (1989): “Hubs and High Fares: Dominance and Market Power in the U.S. Airline Industry,” *The RAND Journal of Economics*, 344–365.
- (2002): “The Trouble with Electricity Markets: Understanding California’s Restructuring Disaster,” *Journal of Economic Perspectives*, 16, 191–211.
- BORENSTEIN, S. AND J. BUSHNELL (2000): “Electricity Restructuring: Reregulation or Reregulation?” *Regulation*, 23, 46.
- (2015): “The US Electricity Industry after 20 Years of Restructuring,” *Annual Review of Economics*, 7, 437–463.
- BORENSTEIN, S., J. B. BUSHNELL, AND F. A. WOLAK (2002): “Measuring Market Inefficiencies in California’s Restructured Wholesale Electricity Market,” *American Economic Review*, 92, 1376–1405.
- BORENSTEIN, S. AND N. L. ROSE (1994): “Competition and Price Dispersion in the U.S. Airline Industry,” *Journal of Political Economy*, 102, 653–683.
- (2014): “How Airline Markets Work? Or Do They? Regulatory Reform in the Airline Industry,” in *Economic Regulation and Its Reform: What Have We Learned?*, University of Chicago Press, 63–135.
- BURKE, P. J. AND A. ABAYASEKARA (2018): “The Price Elasticity of Electricity Demand in the United States: A Three-Dimensional Analysis,” *The Energy Journal*, 39.
- BUSHNELL, J., E. MANSUR, AND K. NOVAN (2017): “Review of the Economics Literature on U.S. Electricity Restructuring,” Working paper.
- BUSHNELL, J., E. MANSUR, AND C. SARAVIA (2008): “Vertical Arrangements, Market Structure and Competition: An Analysis of Restructured U.S. Electricity Markets,” *American Economic Review*, 98, 237–66.
- CICALA, S. (2015): “When Does Regulation Distort Costs? Lessons from Fuel Procurement in U.S. Electricity Generation,” *American Economic Review*, 105, 411–44.

- (2022): “Imperfect Markets versus Imperfect Regulation in US Electricity Generation,” *American Economic Review*, 112, 409–41.
- COASE, R. H. (1960): “The Problem of Social Cost,” *Journal of Law and Economics*, 3, 1–44.
- DAVIS, L. W. AND C. WOLFRAM (2012): “Deregulation, Consolidation, and Efficiency: Evidence from U.S. Nuclear Power,” *American Economic Journal: Applied Economics*, 4, 194–225.
- DERYUGINA, T., A. MACKAY, AND J. REIF (2019): “The Long-Run Dynamics of Electricity Demand: Evidence from Municipal Aggregation,” *American Economic Journal: Applied Economics*, forthcoming.
- EDISON ELECTRIC INSTITUTE (2019): “Profiles and Rankings of Investor-Owned Electric Companies,” Technical report.
- FABRIZIO, K. R., N. L. ROSE, AND C. D. WOLFRAM (2007): “Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency,” *American Economic Review*, 97, 1250–1277.
- FAN, S. AND R. J. HYNDMAN (2011): “The Price Elasticity of Electricity Demand in South Australia,” *Energy Policy*, 39, 3709–3719.
- FOWLIE, M. (2010): “Emissions Trading, Electricity Restructuring, and Investment in Pollution Abatement,” *American Economic Review*, 100, 837–69.
- GREENSTONE, M. AND I. NATH (2021): “Do Renewable Portfolio Standards Deliver Cost-Effective Carbon Abatement?” Working paper.
- HORTAÇSU, A., S. A. MADANIZADEH, AND S. L. PULLER (2017): “Power to Choose? An Analysis of Consumer Inertia in the Residential Electricity Market,” *American Economic Journal: Economic Policy*, 9, 192–226.
- HORTACSU, A. AND S. L. PULLER (2008): “Understanding strategic bidding in multi-unit auctions: a case study of the Texas electricity spot market,” *The RAND Journal of Economics*, 39, 86–114.
- ISHII, J. AND J. YAN (2007): “Does divestiture crowd out new investment? The “make or buy” decision in the US electricity generation industry,” *The RAND Journal of Economics*, 38, 185–213.
- ITO, K. (2014): “Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing,” *American Economic Review*, 104, 537–563.
- ITO, K. AND M. REGUANT (2016): “Sequential Markets, Market Power, and Arbitrage,” *American Economic Review*, 106, 1921–57.
- JHA, A. AND F. A. WOLAK (2023): “Can Forward Commodity Markets Improve Spot Market Performance? Evidence from Wholesale Electricity,” *American Economic Journal: Economic Policy*, 15, 292–330.
- JOSKOW, P. L. (1987): “Contract Duration and Relationship-Specific Investments: Empirical Evidence from Coal Markets,” *The American Economic Review*, 77, 168–185.

- (2005): “Regulation and Deregulation After 25 Years: Lessons Learned for Research in Industrial Organization,” *Review of Industrial Organization*, 26, 169–193.
- KWOKA, J. (2008a): “Barriers to New Competition in Electricity Generation,” *Report to the American Public Power Association, Northeastern University*.
- (2008b): “Restructuring the U.S. Electric Power Sector: A Review of Recent Studies,” *Review of Industrial Organization*, 32, 165–196.
- MACKEY, A. (2022): “Contract duration and the costs of market transactions,” *American Economic Journal: Microeconomics*, 14, 164–212.
- MANSUR, E. T. (2007): “Upstream Competition and Vertical Integration in Electricity Markets,” *The Journal of Law and Economics*, 50, 125–156.
- MERCADAL, I. (2022): “Dynamic competition and arbitrage in electricity markets: The role of financial players,” *American Economic Journal: Microeconomics*, 14, 665–99.
- NEWBERY, D. M. AND M. G. POLLITT (1997): “The Restructuring and Privatisation of Britain’s CEBG-Was It Worth It?” *The Journal of Industrial Economics*, 45, 269–303.
- PULLER, S. L. (2007): “Pricing and Firm Conduct in California’s Deregulated Electricity Market,” *The Review of Economics and Statistics*, 89, 75–87.
- RUBINOVITZ, R. N. (1993): “Market Power and Price Increases for Basic Cable Service Since Deregulation,” *The RAND Journal of Economics*, 1–18.
- RYAN, N. (2021): “The competitive effects of transmission infrastructure in the indian electricity market,” *American Economic Journal: Microeconomics*, 13, 202–42.
- SU, X. (2015): “Have Customers Benefited from Electricity Retail Competition?” *Journal of Regulatory Economics*, 47, 146–182.
- VISCUSI, W. K., J. E. HARRINGTON JR, AND D. E. SAPPINGTON (2018): *Economics of Regulation and Antitrust*, MIT press.

Appendix

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.³⁸ 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 that owned it pre-deregulation.³⁹ We use capacity data at the power plant level from EIA Form 860, which contains information on dates of initial operation and retirement.

³⁸The excluded customer types are transportation, public, and other.

³⁹In the beginning of our sample, the operators coincided with ownership.

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 corporate 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.

When constructing our data, we compared quantities and prices reported by multiple sources (i.e., FERC Form 1 and EIA) or by the same source in multiple places. Overall, reported values lined up well across distinct sources.

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 16 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.

Four states—Arizona, Arkansas, Nevada, and Montana—initially passed deregulation measures but later rescinded them. Michigan allowed for downstream competition but did not restructure the upstream market. We remove these five states from our analysis. We focus on investor-owned utilities (IOUs) that generated electricity in 1994. Because Nebraska and Ten-

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
OR	2002
TX	2002
VA	2002

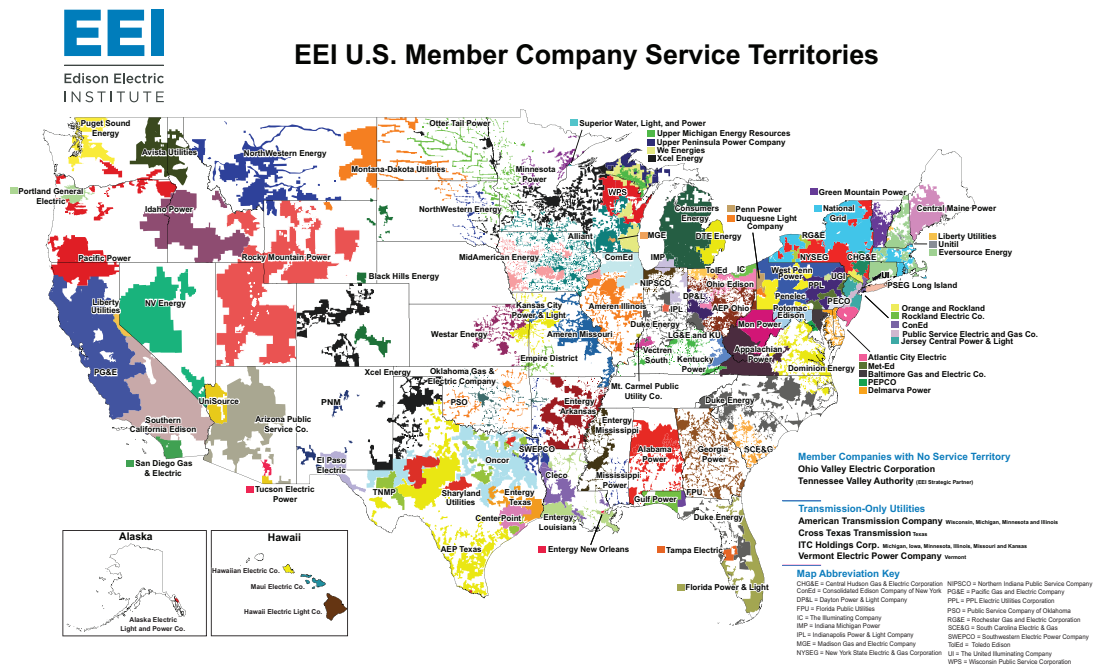
Notes: Table indicates the year initial deregulation measures came into effect for the listed states. For most states, this corresponds to when utilities began to divest generation assets. Michigan (MI) is an exception that did not pass a measure to deregulate the upstream market. Four states (AZ, AR,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

nessee do not have utilities that meet these criteria, we also remove them from the analysis.⁴⁰ We are left with 16 states that introduced competitive markets and 25 states that did not. Our main sample consists of 71 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.

⁴⁰Nebraska 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



Produced by Edison Electric Institute. Data Source: ABB, Velocity Suite, October 2018

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

B Conceptual Framework

Deregulation was expected to bring increased efficiency by providing incentives to reduce costs, since firms that achieve lower costs under market-based prices may earn higher profits. Evidence indicates that in fact deregulated power plants were operated and dispatched more efficiently (Fabrizio et al., 2007; Cicala, 2015, 2022). Although previous research has found 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 imperfections may have in translating efficiency gains into lower prices.

Here, we provide a stylized model of the change in economic incentives and outcomes when moving from regulated to market-based upstream prices. To illustrate this transition, we make a number of simplifications. First, we abstract away from fixed costs. In practice, prices cover fixed costs, including a rate of return on capital. Second, we do not directly model production functions and heterogeneity in generation technology, though this is partially captured by an increasing marginal cost curve. Despite these simplifications, the stylized model captures some key economic tradeoffs that exist in our setting. For our empirical analysis, we attempt to control for the above additional considerations.

Figure A2 illustrates potential upstream prices under regulation and under a market regime. Panel (a) illustrates the case of regulated prices when a utility owns Q^O worth of own generation. For expositional clarity, we assume that the utility owns the least expensive Q^O units in the market. Utility demand, which reflects the demand of its customers, is given by D . The thick black line labeled MC plots the marginal cost curve under a regulated regime.

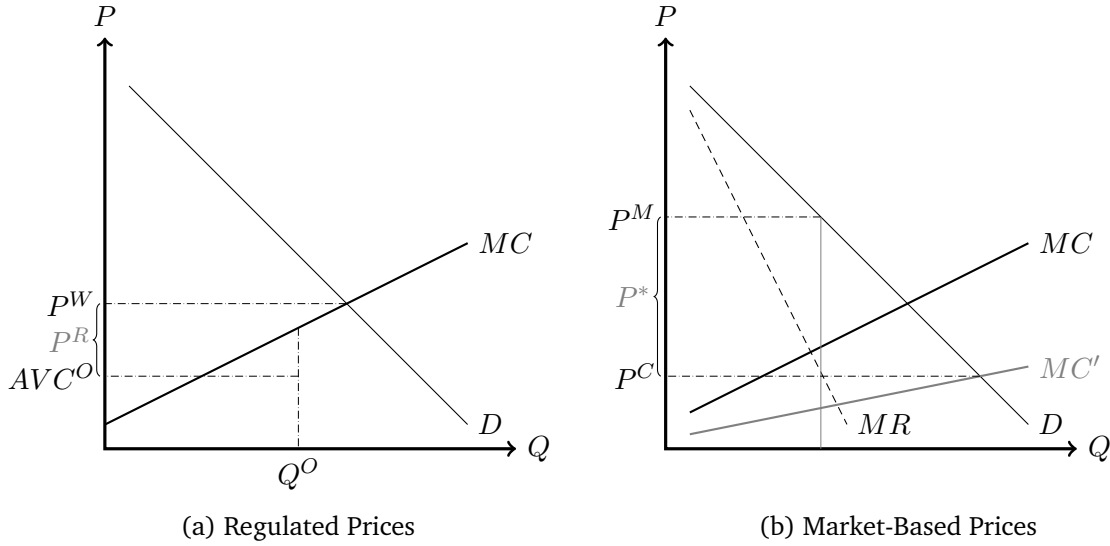
The regulated utility generates Q^O and (due to cost-of-service regulation) is reimbursed based on the average variable cost for its own generation, AVC^O . It fulfills its remaining demand by purchasing from the wholesale market. For simplicity, let us assume that this market is perfectly competitive. The remain quantity is purchased at a competitive price of P^W , yielding an average utility cost P^R between AVC^O and P^W in the regulated regime.

We now consider what happens after deregulation and the divestiture of generation assets by the utility. First, note that utility costs could increase without any change in behavior by market participants. This is because the utility is no longer paying an effective price of AVC^O for the Q^O units it had owned. Instead, it would obtain all of the electricity from the wholesale market at P^W . In this example, P^W is greater than the average price, increasing utility costs.⁴¹

In panel (b), we illustrate the market after considering potential behavioral responses by market participants. 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

⁴¹Though this is not necessarily the case, it is consistent with our data, as we show later.

Figure A2: Regulated and Market-Based Prices for Generated Electricity



Notes: Panel (a) displays a regulated market with utility demand D and the market marginal cost curve MC . The utility produces Q^O units from its own generation assets and is reimbursed based on average variable costs AVC^O for these units. It fulfills remaining demand by purchasing at the competitive market price of P^W , yielding an average price $P^R \in (AVC^O, P^W)$. Panel (b) displays the deregulated market after the divestiture of generation assets by the utility. 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 . 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 .

demand curve with the marginal cost curve, resulting in price $P^C < P^R$. With market power, firms could raise prices up to $P^M > P^R$. 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 market prices P^* ranging from P^C to P^M , depending on the degree of market power and other market imperfections. Thus, this example illustrates how prices could increase even in the presence of efficiency gains.

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 effects using the utility-specific coefficients from our matching approach. We focus on the estimated change in utility costs (average cost of generated and purchased electricity), which factors in the shift to the market from own generation and changes in wholesale prices. For context, we report the implied percent change relative to retail prices.

Table A2 reports the results, which are taken over 2000 through 2016 and weighted by MWh serviced by each utility. The included utilities represent an average of 1,078,000 gigawatts of annual electricity consumption over this period. On average, consumers paid 105 dollars per MWh for electricity in investor-owned utilities in deregulated states. We estimate an that utility costs increased by 8.33 dollars per MWh. Taken on its face, this translates to a 8.6 percent increase in retail prices.

We estimate some heterogeneity across states. Most deregulated states realized meaningful utility cost increases, with 11 states estimated to have an increase exceeding 3 percent of the retail price. We estimate that utility costs decreased in only two states: Virginia and Connecticut.

Table A2: Estimated Impacts by State, 2000–2016

State	Realized Values (\$/MWh)		Estimated Change to Utility Cost (\$/MWh)	Change Relative to Retail Price (%)
	Retail Price	Utility Cost		
MD	100.57	68.09	24.95	33.0
ME	118.36	88.52	21.25	21.9
DE	94.39	71.02	14.11	17.6
IL	80.36	44.96	11.60	16.9
NJ	118.91	75.47	15.93	15.5
PA	91.69	51.38	11.81	14.8
OH	81.25	40.63	9.28	12.9
TX	74.44	41.55	8.19	12.4
NY	146.48	67.45	11.03	8.1
OR	76.19	35.47	2.52	3.4
CA	136.32	55.82	4.11	3.1
RI	131.07	76.74	3.59	2.8
MA	148.06	63.85	3.66	2.5
NH	136.13	62.40	2.04	1.5
VA	75.68	39.59	-0.15	-0.2
CT	145.28	63.36	-23.42	-13.9
All	105.24	53.21	8.33	8.6

Notes: Retail price is the average bundled price weighted by the share of residential, industrial, and commercial customers served by each utility. Utility cost is the average cost of energy to the utility, which is a weighted average of own generation and electricity purchased on the wholesale market. Values are weighted by MWh consumed in each utility's service area. The total annual consumption is 1,078,000 gigawatts.

D Demand and Supply Factors Related to Market Power

In this section, we evaluate different factors that may be linked to the presence of market power in wholesale electricity markets. First, we show that utilities with a more elastic demand, as measured by a higher share of industrial consumers, saw a higher increase in margins. Second, we show that the increase in regulated rates was similar across different types of customers, which is consistent with an exercise of market power in wholesale markets that drove up average utility costs. We then 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. 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.

D.1 Elasticity of Demand

As an additional check to confirm that our findings are driven by firms' market power, we examine how the effects on margins 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 with the incumbent provider (Hortaçsu et al., 2017). Importantly, the proportions of each group in a utility service area are arguably exogenous because 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 margins 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 margins 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 A3 presents results from regressing the estimated effect on margins 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 margins 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

Table A3: Margins and Demand Elasticity

	Wholesale Margin		Gross Margin	
	(1)	(2)	(3)	(4)
Share Residential 1994–1999	90.01** (37.16)		94.62*** (29.72)	
Share Industrial 1994–1999		-116.7*** (13.63)		-85.78*** (10.54)
Constant	-26.78* (15.49)	40.93*** (8.366)	-12.05 (12.47)	47.25*** (9.321)
Year FE	Yes	Yes	Yes	Yes
Observations	537	537	656	656

Notes: *** $p < 0.01$; ** $p < 0.05$; * $p < 0.1$. The dependent variable is the estimated effect on margins, which is regressed on the average share of residential and industrial customers from 1994 through 1999. Gross margin 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.

relatively clean proxy for the elasticity of the demand in that market. We analyze the relationship between margins and demand elasticity using both wholesale margins and gross margins, 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.

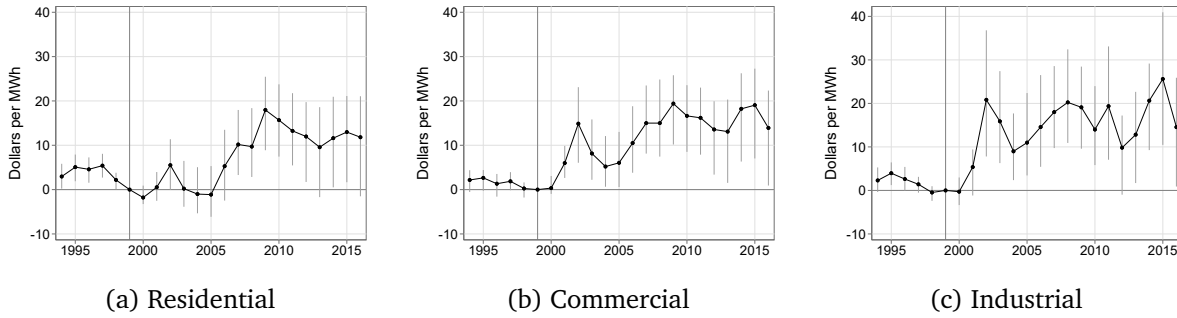
Results in Table A3 indicate that utilities with a higher share of residential customers from 1994 to 1999, which is our proxy for more inelastic demand, had larger increases in margins. We also find that the share of industrial customers has a negative relationship with changes in margins, which would be expected when industrial customers exhibit more elastic demand. These findings are consistent with deregulated firms exerting market power, charging higher margins in markets with more residential consumers and less elastic demand.

D.2 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 expenses for generated electricity. 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 con-

Figure A3: Effects on Utility Rates by Customer Type



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.

sistent 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 A3 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.⁴²

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

⁴²These results further suggest that the significant differences in margins across utilities shown in Table A3 are due to differential upstream behavior, as opposed to downstream price discrimination to different customer types.

of deregulation. We discuss the increase in utility variable costs and the rate freezes in more detail in Sections 5 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.⁴³ See Figure A13 in the Appendix for estimated effects on the consumption of bundled service from the incumbent utility by customer type.

D.3 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.⁴⁴ 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. Although 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.

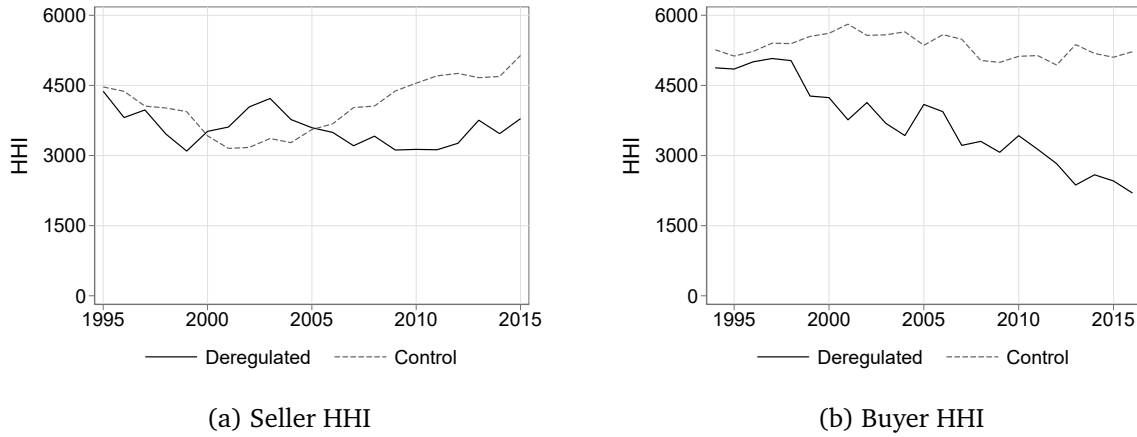
We evaluate changes in concentration in upstream and downstream markets by calculating the Herfindahl-Hirschman Index (HHI) for deregulated and control states. We find that concentration remained high in the upstream market for sellers. Though utilities were forced to divest their generation assets, 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 margins) in deregulated 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 A6 in Section 6). We think this change in the relative balance of bilateral market power may have contributed to the increase in margins in deregulated states.

Panel (a) of Figure A4 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 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

⁴³With the exception of Texas and Maine, which fully eliminated regulated rates for some utilities.

⁴⁴We track ownership up until the ultimate parent company level.

Figure A4: Concentration Upstream and Downstream by Deregulated Status



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. ISO wholesale market purchases are excluded. For sellers, concentration is calculated at the parent company level.

Exelon. Both deregulated and control states were highly concentrated at the beginning of our sample and remained so, with average HHI levels consistently above 3,000.⁴⁵ Despite shifting an increasing share of energy to wholesale markets and encouraging independent generation, seller concentration did not decrease.⁴⁶

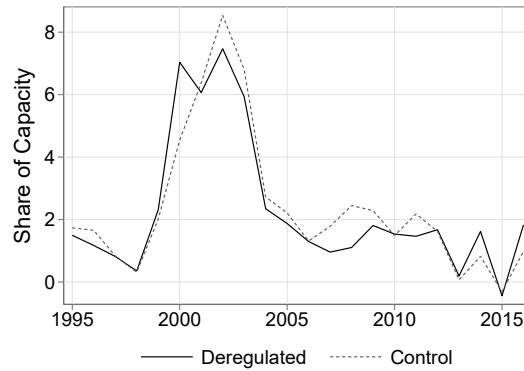
Panel (b) of Figure A4 shows the evolution of the mean HHI among buyers for deregulated and control states, where buyers include both investor-owned utilities and power marketers. Concentration remained roughly constant between 1995 and 2015 in control states. In deregulated states, on the other hand, 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 A4 indicates that concentration among buyers decreased in deregulated 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 margins 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 ones expired. This correlation is not necessarily causal because market concentration is en-

⁴⁵The 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.”

⁴⁶Regulated utilities generate most of their energy, so concentration measures for sellers in control states describe very small markets. After restructuring occurs in deregulated states, concentration measures are more representative because a larger share of the market is traded. Figure A4 excludes purchases from ISO markets, but the figure looks very similar if these purchases are included.

Figure A5: 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 control states. Only operating plants are included.

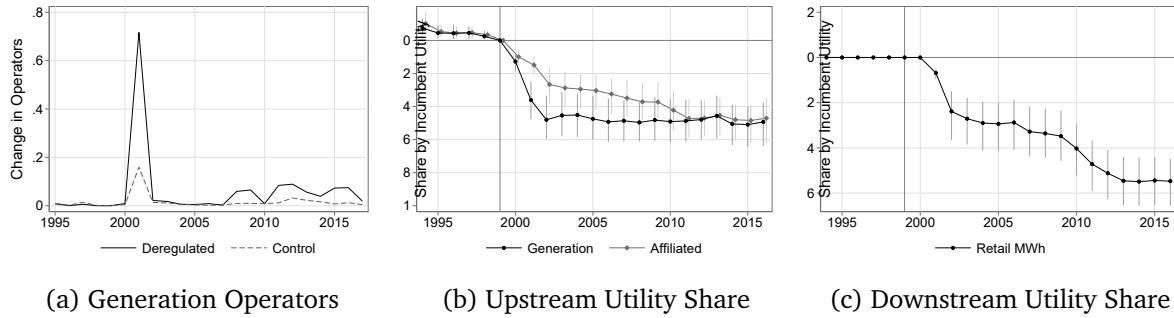
dogenous, but it is consistent with market power as the main explanation for our findings.

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 margins to attract new entrants, so we examine the entry of new generators over time. Persistently high margins are only possible if there are significant entry barriers, because otherwise new firms would enter the market to capture these high profits. Figure A5 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, as 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,⁴⁷ 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.

⁴⁷Thermal 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 A6: Apparent versus Effective Deregulation



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 corporate ownership. Panel (b) shows the change in the incumbent utility's share in the downstream retail market.

E Robustness Checks and Additional Analysis

E.1 Aggregate Delays in Effective Deregulation

Here, we present the estimated delay in effective deregulation arising across all deregulated utilities in our sample. First, in panel (a) of Figure A6, 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 deregulated states 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 occurring from utilities and generators owned by the same parent companies. This measure proxies for the long-term contracts signed by 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 corporate 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 margins 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.

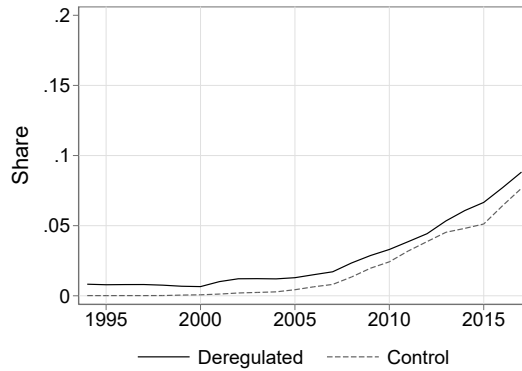
A second restriction that delayed the onset of competitive retail markets was the practice of implementing retail rate freezes in deregulated states. These rate freezes kept retail prices low, making the existing utility attractive to consumers and effectively discouraging new entrants. As shown in panel (b) of Figure 5, deregulated utilities saw a decrease in retail margins from 2000 to 2008. These rate freezes could have delayed the transition to competitive retail markets. As shown in panel (b) of Figure A6, 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 market saw a gradual increase in competitive providers, reaching 52 percent of the market by 2016.

E.2 Additional Details on Other Mechanisms

Renewable Portfolio Standards and Environmental Regulation Since the beginning of restructuring, many states have pursued changes to environmental regulation. Most of these measures were targeted at retail markets, such as energy efficiency programs and net metering for rooftop solar. A notable exception was renewable portfolio standards (RPS), which required utilities to procure a minimum share of the electricity they sell from renewable sources. RPS have the potential to increase prices (Greenstone and Nath, 2021) and might have contributed to increase utilities' costs. 25 states had passed regulation with this kind of requirement by 2007.

Although RPS could have led to higher costs for utilities, we think that RPS are not likely to explain the sharp rise in wholesale prices and margins that we find. Although RPS were more common among deregulated states, those that remained regulated adopted them as well. In 2007, 14 deregulated states and 7 control states had adopted RPS (Greenstone and Nath, 2021). Second, despite RPS adoption being more likely in deregulated states, the gradual

Figure A7: Share of Generation from 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.

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 in place by RPS were not stringent. To illustrate this, Figure A7 shows the share of generation coming from renewable resources—wind, solar, and geothermal—in deregulated and control states.⁴⁸ The figure shows that the shares are nearly identical across the two groups, and they increase at the same gradual rate starting in 2008.

Finally, even if the cost of renewable energy is higher in deregulated states, we think the share of energy from renewable sources is still too low to be the major reason behind the sharp increase in wholesale prices and margins. Renewable energy might be more expensive in deregulated states if those plants were built to satisfy the RPS requirement and not for economic reasons, but the share of generation from renewable sources was below 2 percent when wholesale prices start to increase, and still below 10 percent in 2010.

Other Cost Shocks Over our sample period, the electric industry has faced cost shocks from fuel prices and environmental regulation. How these shocks affected a utility's cost structure depends on the utility's initial generation mix because, for instance, more stringent environmental regulation will be more impactful for, e.g., utilities that rely more heavily on coal to produce electricity. A potential concern would then be that this initial difference in generation mix determined how firms were affected by cost shocks, and not the restructuring process.⁴⁹

Our matching approach allows us to mitigate this concern to some degree, as each utility

⁴⁸Hydropower 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.

⁴⁹For 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.

in a deregulated state is compared to utilities in control states with a similar generation mix in 1994. Though utilities could later change their generation mix, we do not necessarily want to control for these changes as entry and exit decisions may be the result of the deregulation process. If, for instance, deregulated markets attracted more entry by cleaner plants, or by gas plants that could take advantage of cheaper natural gas, this is something that we might want to attribute to our estimates of cost efficiencies. In our data, we observe similar trends in aggregate generation by fuel types across the two groups.⁵⁰

A related concern is that plants may choose emissions compliance strategies that differentially affect their cost structures. Fowlie (2010) compares compliance strategies between deregulated 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 deregulated. Because rate-of-return regulation creates stronger incentives for capital investment, regulated plants chose more capital intensive compliance options than plants in deregulated states. This implies that environmental regulation could potentially have increased fixed cost for regulated plants and variable costs for deregulated plants. If compliance raises variable costs that we do not measure, we could potentially overstate the changes in margins in deregulated 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 about one-third of the wholesale margin difference we estimate over 2008-2016 (see Table 2). Moreover, these costs are not much more than the decrease in fuel cost in deregulated utilities over that period. Thus, such regulations are not likely to explain the changes we estimate.

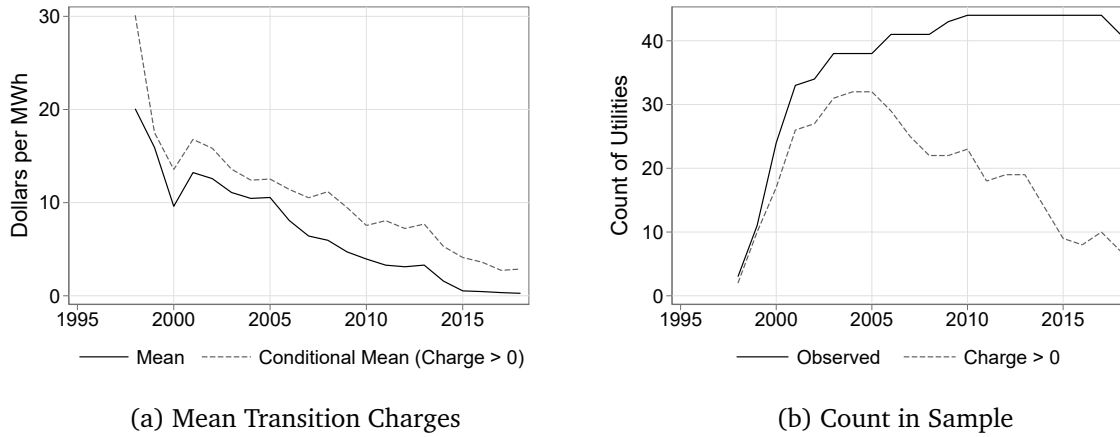
Stranded Costs During restructuring, most utilities reached agreements with state regulatory authorities to levy additional charges on their retail customers related to the move toward deregulation. A common argument by the utilities was that the transition to competitive markets would result in a loss in value of their capital investments, and that they should be compensated for the “stranded” costs of these assets.

We collected information on transition charges, which covered stranded costs, for 44 large utilities across 16 states that passed deregulation measures.⁵¹ 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 A8 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.

⁵⁰The 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.

⁵¹The data were obtained from utility ratebooks or the relevant state regulatory commission.

Figure A8: Transition Charges and Stranded Costs



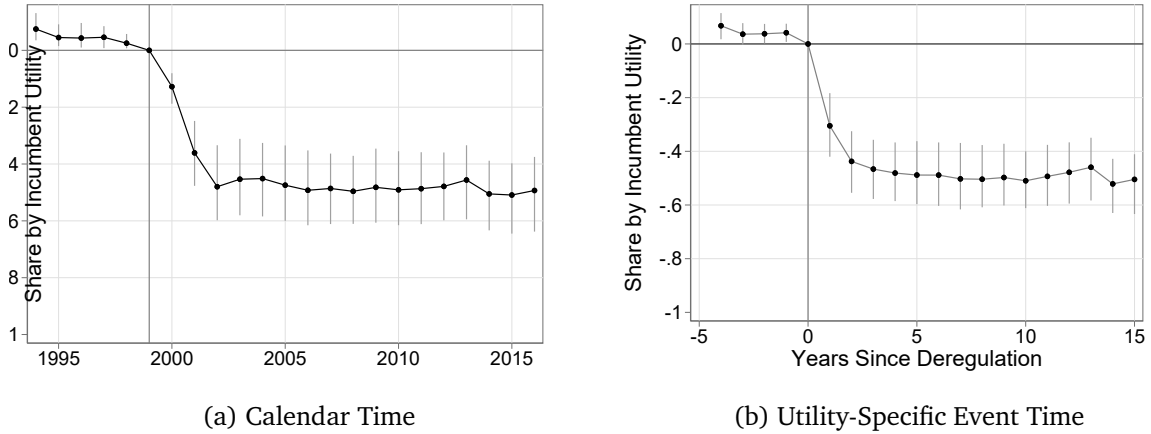
Notes: Figure displays the transition charges levied on customers in deregulated utilities to cover stranded costs and other features of restructuring. Panel (a) plots the mean charges (solid line) and the condition mean for positive charges (dashed line). Panel (b) plots the count of utilities with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

As shown in panel (b), individual utilities phase out stranded costs starting in 2006. The solid 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 margin 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 unlikely that they account for the observed increase in prices in deregulated states. Although it is still possible that stranded costs played a role leading to higher retail rates for some particular utilities, the trends in stranded costs move in the opposite direction from the price changes we observe.

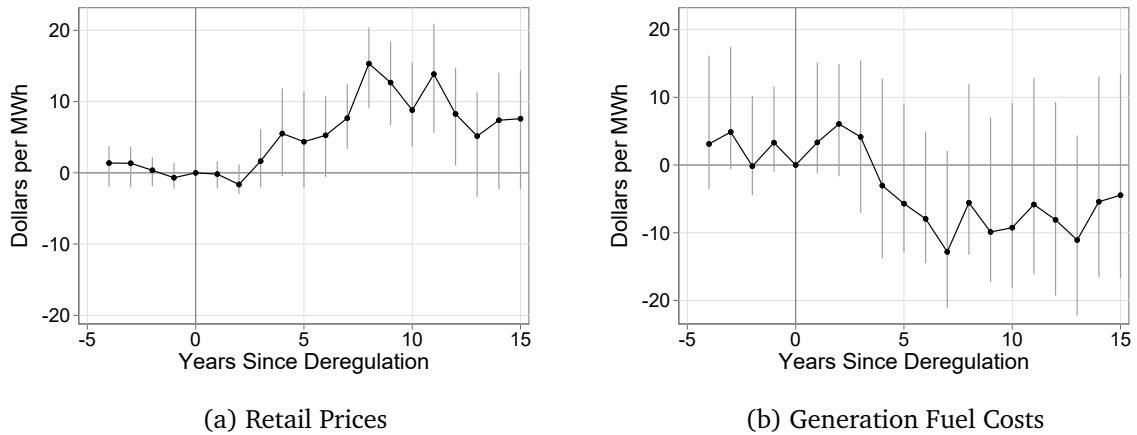
Comparison of Event Timing Approaches

Figure A9: Different Choices of Timing



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.

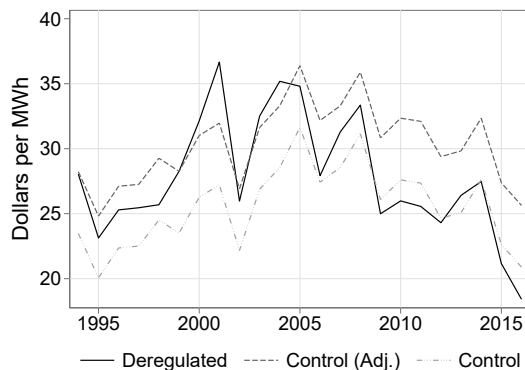
Figure A10: Event Study Estimates of Changes in Prices and Costs After Deregulation



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.

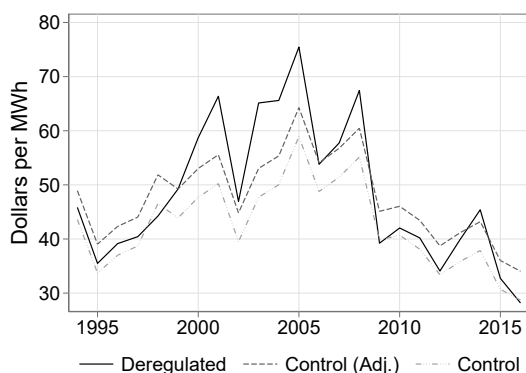
Alternative Measures of Generation Costs

Figure A11: Average Variable Fuel Costs

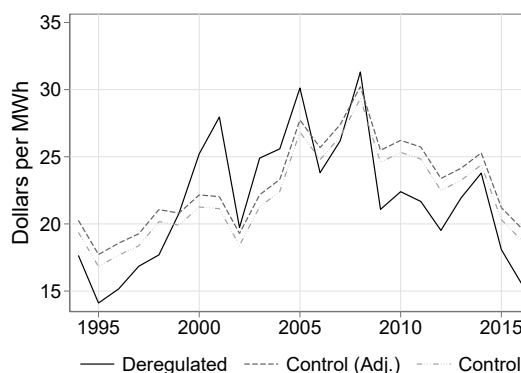


Notes: Figure plots the average fuel costs of generation for all generating facilities in deregulated states (solid black line) and control states (grey line). The dashed line plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

Figure A12: 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 Margins (AVC)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Generation Cost (AVC)	Wholesale Margin	Wholesale Price	Retail Margin	Retail Price	Gross Margin	Utility Cost
1999 Values	27.93	15.43	42.26	35.99	78.57	50.59	33.55
2000-2007	-3.49 (3.62)	2.03 (5.04)	-1.23 (3.15)	6.60 (2.87)	5.74 (1.98)	9.17 (4.74)	4.86 (2.35)
2008-2016	-8.64 (3.97)	19.13 (5.03)	11.76 (3.46)	2.90 (3.40)	11.54 (2.97)	20.20 (5.12)	14.36 (3.27)
2000-2016	-6.20 (3.10)	10.86 (4.20)	5.53 (2.99)	4.44 (2.69)	8.81 (2.25)	14.94 (4.16)	9.59 (2.42)

Notes: Table displays the estimated difference-in-differences matching coefficients for prices, costs, and margins between deregulated and control utilities in dollars per MWh. In this table, costs and margins 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, 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)	15.24	15.22	0.960	15.45	0.708
ln(MWh Generated)	14.74	14.60	0.817	14.61	0.878
Marginal Generation Share: Coal	0.41	0.54	0.294	0.44	0.832
Marginal Generation Share: Gas	0.22	0.15	0.513	0.23	0.967
Marginal Generation Share: Nuclear	0.00	0.03	0.399	0.00	0.293
Marginal Generation Share: Oil	0.21	0.07	0.057	0.17	0.731
Marginal Generation Share: Water	0.15	0.20	0.569	0.16	0.944
Marginal Fuel Costs	69.19	37.52	0.101	63.91	0.845
Retail Price	80.64	58.95	0.001	59.47	0.001
Number of Unique Utilities	71	76		65	

Notes: Table displays 1994 characteristics for 71 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 regions.

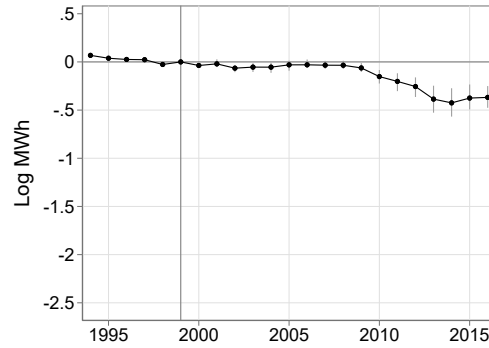
Table A6: Relative Changes in Prices, Costs, and Margins

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Generation Cost (MC)	Wholesale Margin	Wholesale Price	Retail Margin	Retail Price	Gross Margin	Utility Cost
1999 Values	49.92	-6.61	42.26	35.99	78.57	28.60	33.55
2000-2007	-7.18 (3.32)	6.34 (4.37)	0.16 (3.15)	5.65 (2.87)	6.19 (1.98)	13.31 (4.23)	4.69 (2.35)
2008-2016	-13.48 (6.27)	23.20 (7.05)	11.96 (3.46)	2.25 (3.40)	11.10 (2.97)	24.60 (7.03)	14.36 (3.27)
2000-2016	-10.48 (4.28)	14.89 (4.94)	6.28 (2.99)	3.65 (2.69)	8.78 (2.25)	19.20 (4.98)	9.51 (2.42)

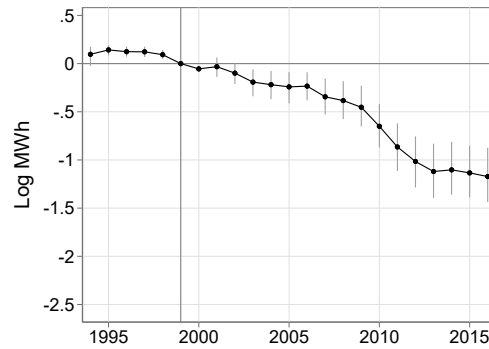
Notes: Table displays the estimated difference-in-differences matching coefficients for prices, costs, and margins between deregulated and control utilities in dollars per MWh. The first row provides the baseline values in 1999, and the remaining rows provide the average effect for the specified time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

Change in Downstream Consumption

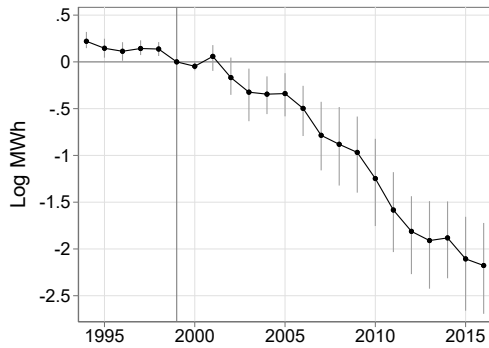
Figure A13: Change in Incumbent Utility Retail MWh (Bundled Service)



(a) Residential



(b) Commercial

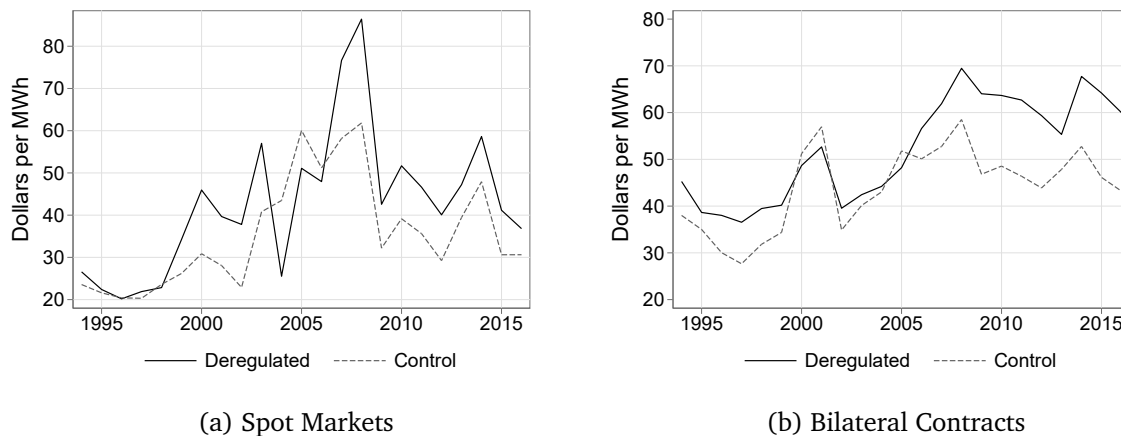


(c) Industrial

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 A14: Wholesale Prices from Spot Markets (ISOs and Power Pools) and 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.