Shades of Integration: The Restructuring of the U.S. Electricity Markets*

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Abstract

We use a detailed dataset on electricity transactions to investigate changes in market structure following the deregulation of the electricity sector, as well as the consequences for prices. We show that deregulation was effectively delayed by intermediate degrees of vertical integration, such as long-term contracts and common ownership. To account for these mechanisms, we look at the impact of *effective deregulation*: the portion of a market served by companies not related to the incumbent utility. We find that effective deregulation occurs several years after the initial vertical separation of incumbent utilities, and, when it occurs, prices increase. Deregulation can have this effect when firms have market power, as the increase in prices from markups may outweigh the cost reductions from allocative and technical efficiencies. We consider alternative explanations and discuss why it is unlikely that they resulted in the observed correlation between prices and retail competition.

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1 Introduction

Motivated by potential efficiency gains, the restructuring of the U.S. electricity sector introduced competition into several markets that traditionally operated as regulated monopolies. This effort, which began in the 1990s, had the objective of bringing down consumer prices. Was the effort successful? Over 20 years later, we have yet to fully understand its consequences (Bushnell et al., 2017). Previous studies have found that generation costs went down in deregulated markets, but it is still unclear if this translated into lower prices for consumers (Fabrizio et al., 2007; Davis and Wolfram, 2012; Borenstein and Bushnell, 2015; Bushnell et al., 2017; Cicala, 2017).

In this paper, we exploit a unique dataset on electricity markets in the U.S. to examine the consequences of deregulation. We highlight a fundamental tradeoff of deregulated markets: market-based prices can reduce costs through the more efficient allocation of resources, but the presence of market power can lead to increased markups. The net effect of deregulation therefore depends on the relative magnitudes of production efficiencies and market power.

Using detailed data on electricity transactions from generation to retail sales, we obtain two main findings. First, we show that the market restructuring intended by deregulation was delayed for several years. Despite the divestiture of generation assets, utilities maintained a high degree of vertical integration through contracts and common ownership. 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.[1] In retail markets, caps on retail rates and other factors slowed the introduction of competitive supply. Second, we find that effective deregulation was correlated with *higher* prices at both the wholesale and retail levels, which implies that deregulation did not fulfill the expectations of lower prices that led states to deregulate. Though our second finding is likely surprising to proponents of deregulation, the result of higher prices is consistent with the move from cost-of-service regulation to a regime where generators and retailers earn markups, as we discuss below.

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 its rates were regulated to avoid monopoly pricing. Following a wave of successful deregulation in other sectors, like telecommunications and airlines, the electricity sector started its own process of deregulation in the 1990s.

The deregulation of the sector was brought about by state-specific policies to introduce competition into generation and retail. The transmission and distribution grids were still considered

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

natural monopolies; therefore, through federal regulation, the transmission grid was put into hands of an Independent System Operator (ISO), whose role was to coordinate the usage of the grid and ensure access to competitive generation. Utilities maintained the distribution lines, regardless of whether their state implemented deregulation measures. In deregulated states, competitive retailers were able to make use of the distribution grid and sell directly to end consumers. These consumers paid a regulated distribution rate to the utility, in addition to paying for the electricity from the retailers.

We introduce our analysis of the upstream generation market and the downstream retail market through a case study of Illinois, where deregulation began in 1997. By 2001, the two large investor-owned utilities had formally divested their generation assets, resulting in near-complete apparent deregulation of the upstream market. However, we show that incumbent utilities still obtained a majority share of their purchases from affiliated companies, i.e., companies belonging to the same parent company. Unaffiliated power producers did not capture a majority of the generation share until 2007, when a centralized procurement mechanism was introduced. Downstream, deregulation was delayed because retail competition was initially introduced only for large commercial customers. Even though residential and small commercial customers technically had a competitive market starting in 2002, the utility rates had been lowered and frozen through 2007, limiting the impact of retail choice for these segments. At the expiration of the rate freeze, the incumbent utilities realized a drop in retail sales.

Deregulation was therefore effectively delayed for 10 years, since most generation and retail sales remained under the control of the incumbent utilities. When effective deregulation was realized, wholesale prices paid by incumbent utilities increased sharply. To account for potential confounding factors, we compare wholesale prices to those for Missouri and Iowa, neighboring states that remained regulated. Furthermore, the largest utility in Missouri also belongs to the same parent company of the largest utility in Illinois. We show that wholesale prices in the three states moved in sync before Illinois was deregulated, and also until 2007. In that year, when market structure effectively changed as a consequence of deregulation, prices in Illinois spiked and stayed at higher level than prices in Missouri and Iowa. Similarly, retail prices in Illinois also spiked in 2007.

To confirm that this is a general finding and not particular to Illinois, we extend our analysis to (formerly) regulated utilities across the United States. As in Illinois, we find that the intended market restructuring was slow to develop. In the upstream market, effective deregulation lagged apparent deregulation by as many as 10 years. Though utilities legally divested themselves of their generation assets quickly, these assets were sold to a subsidiary of the same parent company and continued to supply the affiliated utility. In other words, despite being formally different companies, they were only one step below complete vertical integration since they had common ownership and control. Moreover, the affiliated purchases tended to be governed by long-term contracts, which brought the firms closer to vertical integration. At the downstream level, competition also took some time to intensify, since consumers were slow to switch and the incumbent utility kept a high market share for years.[2]

After showing the delay in effective deregulation across the U.S., we estimate its effect on prices. We conduct the analysis at the utility level using regulated states as a control group, include utility and year fixed effects, and control for fuel prices at the state level. Our results indicate that both upstream and downstream prices increased after deregulation. Our event study shows that prices increased over 10 $/MWh, which corresponds to roughly 21 percent of wholesale prices and 13 percent of retail prices in the year 2000. After controlling for the degree of downstream deregulation, we find that effective upstream deregulation is correlated with lower prices, confirming efficiency gains documented in the previous literature (Fabrizio et al., 2007; Davis and Wolfram, 2012). However, the upward pressure on prices is an order of magnitude higher. Thus, we find that the generation efficiencies were overwhelmed by the other effects of deregulation.

The fact that prices increased after deregulation comes somewhat unexpectedly, since arguments to deregulate are typically based on competition bringing down prices. Nonetheless, there are standard market forces that would tend to increase prices. First, upstream deregulation allowed generators to charge markups to (previously integrated) downstream retailers. Second, downstream deregulation allowed competitive retailers to charge markups over these wholesale costs, whereas regulated utilities were reimbursed based on average procurement costs for electricity. Thus, in addition to allowing for the exercise of market power, deregulation also brought about the potential for double marginalization by vertically separating the two markets. Finally, there is an interaction between the two: with increased downstream competition, market power increases upstream, as generators have more choices over which retailer they sell to. This could further increase markups charged in the upstream market. One interpretation of our findings is that the regulation of electricity markets was consumer-friendly: consumers were paying for electricity at cost, and the efficiency gains of introducing profit incentives to the generation market were modest.[3]

Finally, we use transaction level data on electricity sales from FERC Electric Quarterly Reports (EQR) to analyze the role of vertical integration for the case of Illinois. Here, as in many states, the share of purchases from affiliated companies falls at the time retail competition intensifies, when we also find that prices go up. We show that for the case of Illinois, this increase in prices comes primarily from purchases that occur under long-term contracts with affiliated companies. Most of these contracts were signed in 2007, suggesting it was yet another attempt of incumbents to delay changes in market structure from deregulation, though they might not have been as effective once competitive retailers started to gain larger market shares.

[2]Hortaçsu et al. (2017) study the reasons behind this initial inertia in Texas, which we show was the general trend in deregulated states.

[3]A long-run effect of the introduction of competition could be more efficient investment in generation facilities. We set aside this question for the paper.

We consider alternative explanations, and we find that differential changes in fuel costs, stranded cost charges, and cream skimming do not explain the differences in prices we observe. Our estimates suggest that these mechanisms move prices in the opposite direction of our main findings at the time of effective deregulation. In addition, controlling for the effects of renewable portfolio standards makes little difference for our estimates.

This paper's main contribution is to present the first complete description of how U.S. markets changed after deregulation, including both the upstream and the downstream markets. We are able to do this by exploiting two rich datasets that have not been used before. These are: FERC Form 1, which contains detailed information on (formerly) regulated utilities, including costs and procurement sources, and FERC EQR, which contains contractual details of most electricity sales at the wholesale level, except for those in spot markets.

Combining these data, we are able to introduce a new dimension to the analysis of electricity markets restructuring, namely vertical integration. We show that accounting for intermediate degrees of vertical integration is key to understand how markets responded, since they used them to effectively delay the loss of market control by the incumbent utility.

Bushnell et al. (2008) and Mansur (2007) discuss the role of vertical integration in deregulated markets and show that spot wholesale electricity markets are more competitive when generators are vertically integrated because they have fewer incentives to increase prices. Our paper complements these finding by looking at the market as a whole instead of focusing on the spot market, which constitutes roughly 15 percent of the entire wholesale market in deregulated states. We also account for intermediate degrees of vertical integration in the analysis.

The existing literature on the consequences of deregulation is surprisingly scarce, given the importance of the electric sector for the economy and, more recently, for decarbonization. We know that deregulation has brought some gains in productive and allocative efficiency (Fabrizio et al., 2007; Davis and Wolfram, 2012; Cicala, 2017), but we still do not know what was the effect on prices (Bushnell et al., 2017). We are the first to document that effective deregulation is correlated to higher prices upstream and downstream.

The next section of the paper describes the data sources used in this paper. The core of the paper is in Section 3, we describe the restructuring process of the United States and analyze the changes it brought to market structure using data for all states. We discuss our findings on the effect of deregulation on prices in Section 4, and conclude in Section 5.

2 Data

Our dataset is constructed using data from several sources. Data on electric utilities comes from FERC Form 1, which is completed annually by all electric utilities. This dataset contains financial information, as well as data on purchases (how much, from which company, at what price) and sales (retail by type of customer, wholesale), as well as generation costs when applicable. We combine this with data from forms EIA-861 and EIA-923 from the Energy Information Administration (EIA). This dataset has been combined and cross-validated with industry data obtained from S&P Global.

A second source of data are the Electric Quarterly Reports (EQR) collected by FERC, where most sellers of electricity are required to report their sales and the details of the contract under which they take place. For each wholesale sale of electricity in the US, firms report the price and quantity, the seller and buyer's name, and the contract terms of the transaction. Independent System Operators (ISOs) are not required to report, so in this dataset we do not observe transactions in which utilities purchase in the spot market organized by the corresponding ISO.

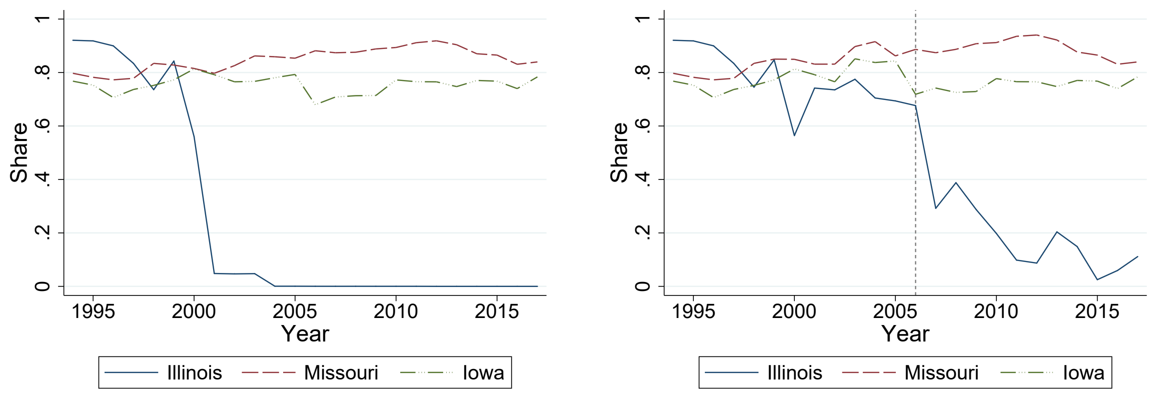
3 Restructuring of the U.S. Electricity Markets

Traditionally, electric utilities operated as vertically integrated companies, owning and managing the plants that generate electricity, the transmission of generated electricity on the electric grid, and the distribution or delivery of electricity to each household or business. The supply of electricity was considered to be a natural monopoly, which is a market where unit costs are minimized when there is only one firm due to economies of scale. For this reason, in most countries it used to be the case that only one firm was allowed to operate in each local market. In the U.S., electricity firms were typically privately owned. Prices were regulated to allow firms to recover investment and earn a "reasonable" return, as determined by the regulator, while staying below monopoly prices.

Following successful deregulation stories in other industries like airlines, ground transportation, and telecom, the U.S. initiated deregulation measures of the electricity sector in the 1990s. Though utilities were still given exclusive rights to the distribution grid, other components of supply—generation and selling to consumers—were not considered natural monopolies. The regulators hoped that the deregulation measures would inject competition into the market and result in more efficient generation and supply. These measures generally consisted of lowering barriers to entry for new firms while relaxing constraints on the prices firms can charge.

The consequences of deregulation in electricity markets are particularly important given how fundamental this sector is in the economy. Electricity is indispensable both as an input in most production processes and as a component of every household's daily life. Moreover, we need a good understanding of electricity markets function in order to overcome the challenges brought by decarbonization, which will require a deep change in the structure of generation in order to replace fossil fuels and serve a demand that will grow with the electrification of transportation and heating.

Figure 1: Share of Electricity Sources



(a) Own Generation

(b) Affiliated Sources

Notes: The affiliated sources include both own generation and purchases from companies belonging to the same parent company. The year 2006 is indicated by a vertical dashed line. Source: FERC Form 1 data.

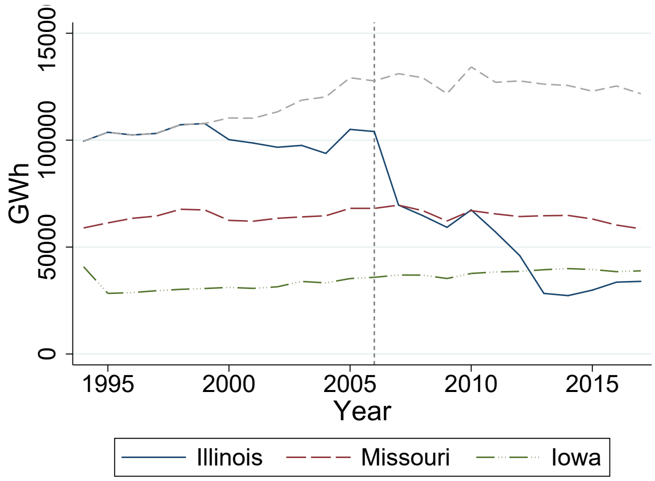
3.1 A Case Study: Illinois

In the 1990s, Illinois' electricity rates were among the highest in the United States. Motivated by these high prices, Illinois lawmakers passed the Consumer Choice Act in 1997, which encouraged large investor-owned utilities to divest their generation assets and allowed for independent companies to supply electricity to commercial customers. For residential customers and small businesses, rates were lowered by 15 percent and frozen for 10 years. In 2002, retail choice was extended to residential and small commercial customers, thus allowing for competitive supply in the downstream market.

Within a few years, the investor-owned utilities in Illinois had sold off their complete portfolio of generation assets. This large change to the market is illustrated in panel (a) of Figure 1. The blue 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 5 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 1 plots the share of own generation for Missouri utilities in red and for Iowa utilities in green. While deregulated firms in Illinois divested nearly all of their generation assets, the regulated firms in Missouri and Iowa continued to obtain the vast majority of their electricity from own generation.

Figure 2: Retail Sales



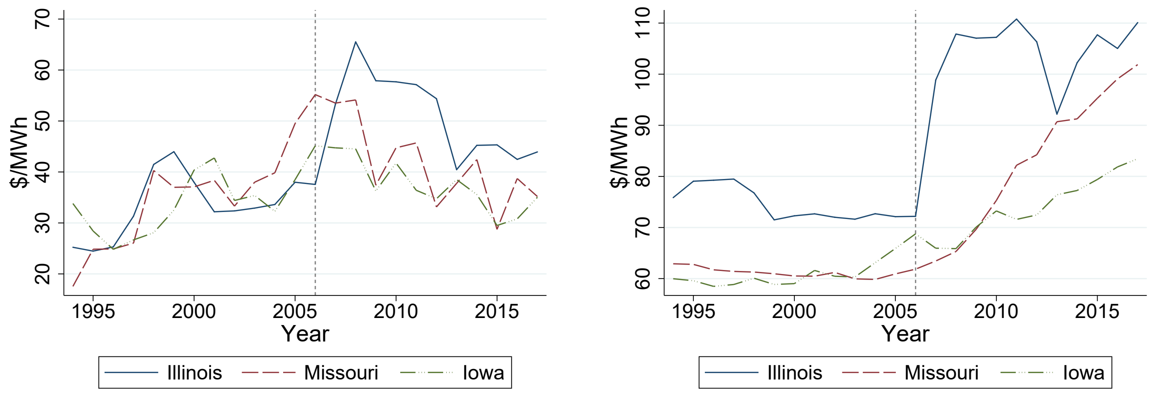
Notes: The blue line represents retail sales by deregulated utilities in Illinois and the gray dashed line represents all retail sales in the utilities' geographic footprint. The difference between these two lines are sales by independent retailers. The year 2006 is indicated by a vertical dashed line. Source: FERC Form 1 data.

Even though deregulated firms legally divested themselves of generation assets quickly, the actual restructuring of the upstream market came about more slowly. Indeed, this is one of the key empirical facts of our paper, and can be observed in Figure 1. Panel (b) 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.

To examine the effect of the restructuring measures on the downstream market, we consider retail electricity supplied by investor-owned utilities compared to sales from independent power producers and power marketers. As in the upstream market, the conditions in the downstream market changed slowly. From 1997 to 2006, only commercial customers were incentivized to choose electric providers, resulting in a modest decline in sales for incumbent utilities. Figure 2 plots retail sales for the deregulated utilities (blue line) compared to retail sales in the utilities' geographic footprint (gray dashed line). Though formally deregulated, during this period the market remained similar to how it was before deregulation started: Incumbent utilities served most of the market and rates were frozen.

In 2007, the price cap on rates was removed and several long-term purchase agreements expired. Figure 2 shows that the incumbents then realized significant declines in market shares. Additionally, Illinois began implementing additional incentives to encourage retail choice, such

Figure 3: Prices



(a) Upstream (Wholesale)

(b) Downstream (Retail)

Notes: Purchase prices reflect the quantity-weighted average price of purchased electricity, including long-term contracts and spot-market transactions. Retail prices are calculated based on all revenues to the utility and include transmission and delivery fees. The year 2006 is indicated by a vertical dashed line. Source: FERC Form 1 data.

as municipal aggregation (Deryugina et al., 2019). Municipal aggregation was first implemented in 2010, increasing the share of retail electricity supplied by independent power companies, which surpassed 50 percent of the market in 2011.

Utilities did not change their real purchase patterns until 2007 (Figure 1) and downstream competition did not take off until that year. Thus, effective deregulation, measured by the impact on market restructuring, did not occur in Illinois until 2007. Beginning that year, retail choice was much more common and most transactions were between independent parties.

Deregulation was expected to bring down prices by reducing inefficiency and increasing the competitiveness of the sector. Surprisingly, wholesale electricity prices in Illinois increased after 2007, when deregulation had effectively taken place. This is illustrated in panel (a) of Figure 3. 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, prices in Illinois spiked, and then stayed above prices paid by regulated utilities. Part of the spike in 2007 may have been due to the design and implementation of a procurement auction for retail customers, but this does not seem to be the whole story since prices remained higher for deregulated utilities even after the auction issues were fixed.

Panel (b) plots the downstream retail prices. The blue 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 gap between Illinois and the comparison states remained substantially larger through 2012.[4] To a first order, it does not

[4]As part of the deregulation measures, customers in Illinois were charged for "stranded costs" that were meant

seem plausible that deregulation resulted in lower prices for Illinois consumers.

The case study of Illinois illustrates two potentially surprising results for policies intended to deregulate a market. First, firms have access to mechanisms (e.g., contracts and common ownership) to maintain a strong degree of vertical integration even when the legal entities are vertical separated. Second, deregulation could potentially *increase* prices. The economic reasons for price increases resulting from deregulation are standard economic arguments, though they are less frequently discussed than their counterparts. We discuss these arguments and the evidence for them in Section 4.

Though we find this case compelling, there may be idiosyncratic reasons that generate (especially) the price patterns we observe in Illinois. In the next section, we expand our analysis beyond Illinois, Missouri, and Iowa to examine how systematic are the delays in effective deregulation and whether the prices indeed increased across a broader sample.

3.2 Aggregate Impacts of Electricity Restructuring

In this section, we examine the overall impacts of electricity market deregulation measures on market structure and prices. To do so, we use detailed annual transaction data for major electricity market participants in the United States. As deregulation measures primarily targeted investor-owner utilities (IOUs), we restrict our analysis to electricity delivered by these companies. Prior to deregulation, IOUs generated the majority of electricity in the U.S.

The geographic footprint of investor-owned utilities remained largely unchanged during our sample period, and utilities remain involved in maintaining the power lines even when electricity is supplied by an independent company. Thus, our dataset is best though of as a geographic subset of the United States, where the included area are the areas serviced by investor-owned utilities. We observe all electricity that flows through the utilities' lines. Our dataset includes generation (if owned by the IOU), purchases made by the IOU, sales for resale, and retail sales. We also observe electricity that is delivered by the IOU as a service for an independent power company. Importantly, we observe whether a company that the IOU sells to or purchases from is owned by the same (ultimate) parent company, so we can measure purchases from these affiliated companies.

To estimate the aggregate impact, we divide our states into two groups: a treated group that includes states that passed deregulation measures, and a control group that did not. Four states—Arizona, Arkansas, Nevada, and Montana—initially passed deregulation measures but later rescinded them. These four are omitted from our analysis. We are left with 17 states in our treated group and 28 states in the control group.

The 17 states that implemented deregulation measures in our period (1994–2016) are re-

to reimburse utilities for the losses on selling their plants. These were in effect from 2001 through 2006, so they do not explain the observed increase in prices. Nor does the spike in natural gas prices around 2007, since it was a temporary increase and prices quickly went down in the following years, unlike retail electricity prices in Illinois.

Table 1: Year of Initial Deregulation Measures

State	Upstream	Downstream
RI	1997	1997
NY	1997	1998
CA	1998	1998
NH	1998	1998
MA	1999	1998
PA	1999	1999
NJ	1999	1999
DE	1999	1999
MD	1999	2000
CT	1999	2000
IL	2000	2000
ME	2000	2000
OH	2001	2001
TX	1995	2002
VA	2002	2002
OR	2002	2002
MI	-	2002

Notes: Table indicates the year initial deregulation measures came into effect for the listed states, by whether they affected the upstream market or the downstream market. Michigan (MI) 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. SD appears to be affected by policies that also affected MT in our data. These five states are omitted from our analysis.

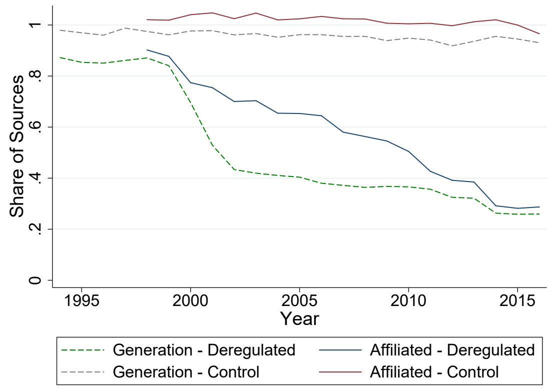
ported in Table 1, along with the year the first measure came into effect for the upstream and downstream markets. With the exception of Texas, all of the states implemented these measures between 1997 and 2002. For our current analysis, we generate our plots relative to a benchmark year of 1995.[5]

Figure 4 indicates the aggregate degree of market restructuring over time. Panel (a) shows the share of electricity sources obtained from own generation for deregulated states (dashed green line) and control states (dashed gray line). Across the treated states, own generation fell sharply from 1998 to 2002, from roughly 90 percent of sources to less than 50 percent. By contrast, the share of own generation for control states remained roughly constant over the entire sample. The share is reported with electricity demand as the denominator, which is why it is possible for the share to be greater than one (the excess electricity is lost on the lines or exported).

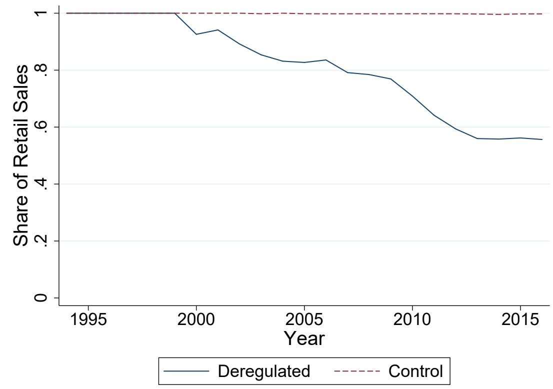
The solid lines indicate the share of electricity sources obtained from affiliated companies. For deregulated states, the decline in electricity purchased from affiliated companies lagged the

[5] We may use state-varying implementation dates in a future version.

Figure 4: Share of Market Supplied by IOUs (1 – Effective Deregulation)



(a) Upstream



(b) Downstream

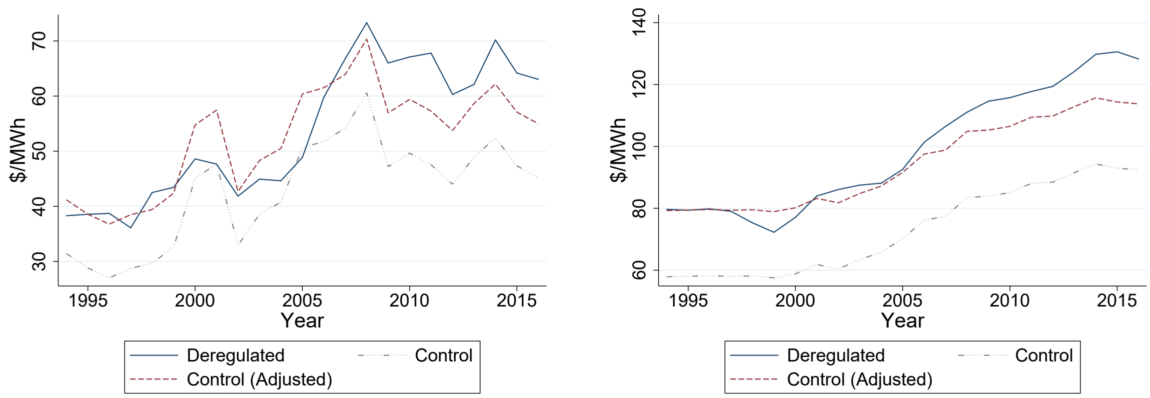
Notes: Source: FERC Form 1.

decline in own generation by several years. It was not until 2011 that non-affiliated purchases reached the level of *effective deregulation* indicated by generation assets in 2001: more than 50 percent from independent companies. These two measures converge toward the end of our sample, with over 70 percent of the aggregate demand being provided by companies independent from the IOUs. Overall, panel (a) suggests that IOUs were able to delay the effects of market restructuring and maintain effective vertical integration.

Panel (b) of Figure 4 indicates aggregate effective deregulation in the downstream market. Much like the path for affiliated purchases, the transition to a deregulated market occurred gradually over a number of years. In the aggregate, the downstream market realized less deregulation than the upstream market, with independent companies providing less than 50 percent of retail consumption in 2016.

We now examine the aggregate effects on wholesale prices (upstream) and retail prices (downstream). Panel (a) of Figure 5 shows the average wholesale price for the two groups. After accounting for level differences, the plot shows that wholesale prices for deregulated states and control states tracked each other closely from 1994 to 1999. In 2000, wholesale prices in control states rose relative to the treated states, and they remained higher (relative to the baseline) until 2006. In 2007, wholesale prices increased in deregulated states. This timing coincides with effective deregulation exceeding 40 percent of the upstream market (Figure 4), as well the expiration of the rate freeze in Illinois discussed in the previous section. Further, panel (b) in Figure 5 shows that retail prices in treated and control states followed a similar pattern until 2007, at which point retail prices in treated states increased. These time-series patterns show that (effective) deregulation is positively correlated with upstream and downstream prices in the time series, though, at least initially, long-term contracts and other initiatives may

Figure 5: Deregulation and Electricity Prices



(a) Upstream

(b) Downstream

Source: FERC Form 1.

have suppressed prices in the deregulated markets.

3.3 Utility-Level Analysis

For a more thorough analysis, we employ regression models using data from individual utilities. We wish to explore the mean effect of deregulation measures on an individual utility, controlling for other factors.

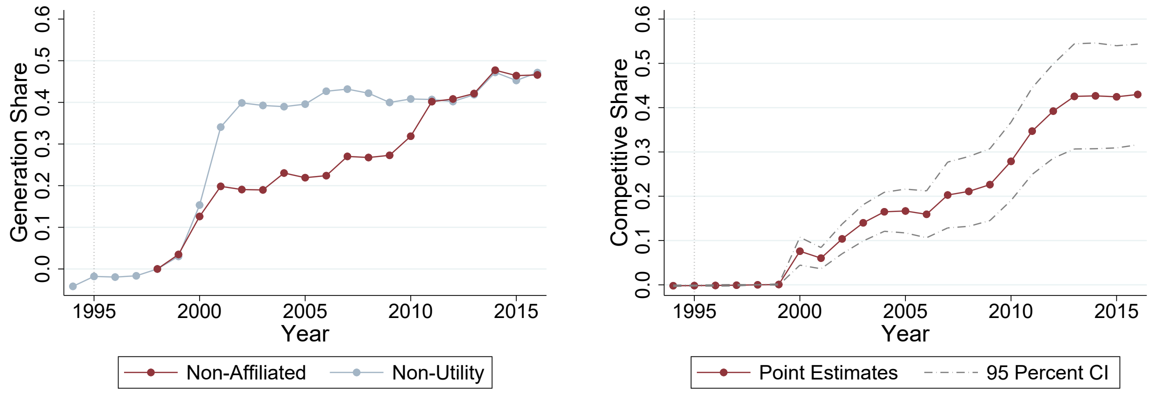
To begin, we use an event-study regression to estimate the following model:

$$y_{it} = D_i \beta_t^y + \xi_i + \phi_t + \varepsilon_{it} \tag{1}$$

Where y is the outcome of interest, i indexes utilities, t indexes years, and D is an indicator for whether or not the utility is in a treated state. We control for utility fixed effects (ξ_i) and yearly fixed effects (ϕ_t). Our coefficients of interest, $\{\beta_t^y\}$, capture the time-varying difference between treated and control utilities in our sample, after accounting for fixed effects.

For our first set of regressions, we calculate effective deregulation compared to apparent deregulation. For the upstream market, we estimate equation (1) where y indicates the share of IOU sources that are purchased (non-utility) and the share of that are purchased from non-affiliated companies. The latter measure corresponds to our notion of effective deregulation. The estimates for β_t^y are plotted in panel (a). Corresponding to our aggregate findings, the average utility divests a substantial portion of its own generation quickly, with over 35 percent divested by 2001. However, utilities continue to purchase from affiliated companies, and effective deregulation does not pass 35 percent until 2011, ten years later. Effective deregulation

Figure 6: Event Study: Effective Deregulation



(a) Upstream

(b) Downstream

Notes: Point estimates are constructed from time-varying regression coefficients. Regressions are weighted by GWh demanded in the geographic footprint of the utility. Source: FERC Form 1.

and apparent deregulation converge at 40 percent for the average utility in 2011, roughly 10 years after the wave of deregulation initiatives.

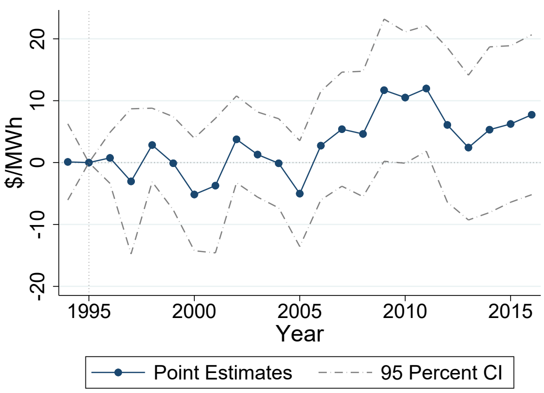
In panel (b), we plot the coefficient estimates for effective deregulation from the downstream market. As in the upstream market, the move toward effective deregulation is gradual for the average utility. In contrast to the aggregate statistics, deregulation in the downstream market reaches approximately the same level as the upstream market, roughly 40 percent by 2013. Downstream (or retail) deregulation lags upstream deregulation by a couple years.

Next, we construct event-study estimates for the effect on prices both upstream and downstream. These estimates are plotted in panels (a) and (b) of Figure 7. For the average utility, we find that wholesale price remain roughly the same for deregulated and control utilities through 2005. Starting in 2006, wholesale prices increase for the deregulated utilities, with statistically significant differences from 2009 to 2011. We observe similar patterns for retail prices, with prices in deregulated states rising around 2006. Retail prices are significantly higher than in the control states from 2009 through 2016. We find no strong evidence of pre-trends in wholesale prices or retail prices leading up to deregulation, as the prices are relatively constant from 1994 to 1997.[6]

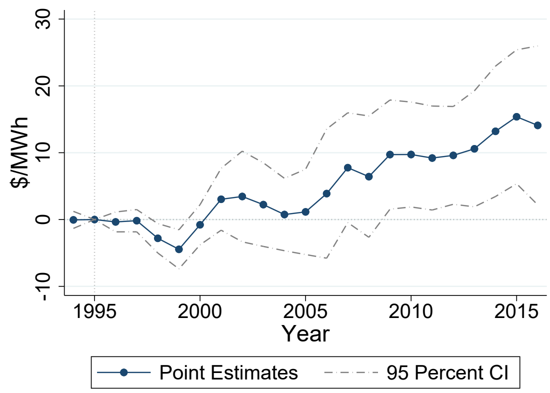
The event study results thus far described indicate delayed impacts of market restructuring and suggest a positive effect of deregulation on prices. However, we wish to control for the fact that these deregulation measures occur at the same time, as well as for other factors (such as fuel costs). We construct estimates of the impact of deregulation on prices with variations of the following regression model:

[6]The estimated confidence intervals are relatively large in the event study plots because they are calculated for each (yearly) coefficient.

Figure 7: Event Study: Upstream and Downstream Prices



(a) Upstream



(b) Downstream

Notes: Point estimates are constructed from time-varying regression coefficients. The upstream price regression is weighted by GWh purchased by the utility. The downstream price regression is weighted by retail GWh by the utility. Source: FERC Form 1.

$$price_{it} = \beta^U E^U_{it} + \beta^D E^D_{it} + \gamma X_{it} + \xi_i + \phi_t + \varepsilon_{it} \tag{2}$$

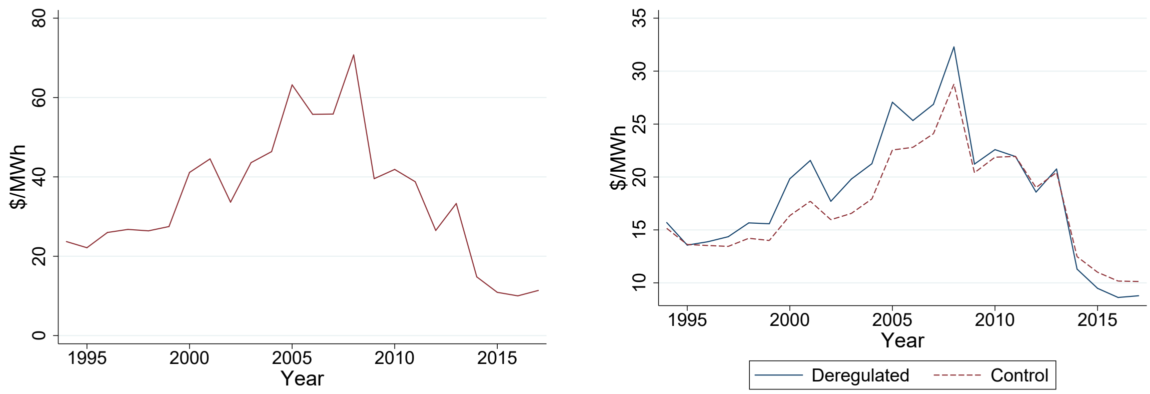
As before, i indexes utilities and t indexes years, and we control for utility fixed effects (ξ_i) and yearly fixed effects (ϕ_t). E^U and E^D measure effective deregulation (the share of supply comping from independent power companies) upstream and downstream, respectively. Thus, our coefficients of interest β^U and β^D capture the net correlation of effective deregulation on prices.

We use time-varying controls, X_{it}, to account for differential changes in fuel costs across states. Borenstein and Bushnell (2015) hypothesize that one reason for increased retail prices in restructured states is that they had a higher share of natural gas generation and were therefore more exposed to natural gas prices.[7] To account for this possibility, we include state-level average variable costs of generation[8] as a control in our model. However, an examination of the time series of natural gas prices and fuel costs shows that fuel costs are unlikely to explain the divergence in prices occurring in 2007 and beyond. Panel (a) of Figure 8 plots the time series of the average variable costs for natural gas plants over our sample. Natural gas prices to rise to a peak in 2008, but decline rapidly after that and fall below the 1998 price. Indeed,

[7]Borenstein and Bushnell (2015) also find different baseline empirical patterns, estimating that retail prices in restructured states did not increase from 2007–2012. We have not yet entirely understood the discrepancy, though we suspect it may be because we only include prices for investor-owned utilities. Our estimates of retail prices are similar for not restructured states and restructured states in 2012, but our estimates of average retail prices are meaningfully lower in 1997 and 2007.

[8]Essentially, fuel costs.

Figure 8: Variable Costs of Generation



(a) Natural Gas

(b) All Fuel Types

Notes: Panel (a) plots the average fuel cost for natural gas. Panel (b) plots the average fuel costs across all generation types, split by control states and states that faced deregulation measures. Source: EIA.

the greater exposure to natural gas prices results in a decline in average fuel costs for the deregulated states in our sample, relative to the control states, in 2009 and beyond. Panel (b) plots the average fuel costs for deregulated and control states. Thus, fuel costs cannot explain the price increases we observe as move in the opposite direction from prices in restructured states.

Table 2 presents our main regression results for the effect of deregulation on upstream prices. We find that downstream deregulation is strongly correlated with higher wholesale prices. The coefficient on our effectively deregulation measures are the linear projection of the impact were a state to go from no effective deregulation ($= 0$) to full deregulation ($= 1$). Thus, in our preferred specification, model (4), the coefficient may be interpreted as: the average IOU territory, which realized an effective downstream deregulation share of 0.43, realized an increase in wholesale prices of $0.43 \times 35.821 = 15.4$ ($/MWh). This is a large number, but it is in line with the effects observed in Illinois (see Figure 3). Relative to the average upstream price of 48.6 $/MWh in 2000, this corresponds to a 31 percent increase. We discuss the economic mechanisms that could account for this increase in the following section. Our estimates are robust to controlling for fuel costs, which have estimated magnitudes that seem reasonable and in line with economic theory (between 0.51 and 0.86). To partially account for the possible endogenous response our measure of downstream deregulation to prices, we present an instrumental variables specification in model (6). Here, we instrument for downstream regulation with the share of retail customers that are commercial and industrial.[9] We expect the distribution of customer types to be correlated with the effectiveness of deregulation measures, but we

[9]The first-stage F-statistic is 138.7.

Table 2: Dependent Variable: Upstream Prices ($/MWh)

	(1)	(2)	(3)	(4)	(5)	(6)
Upstream Deregulation	10.633***		−1.437	−2.424	−2.675	−7.760**
	(3.085)		(3.387)	(3.124)	(3.136)	(3.687)
Downstream Deregulation		33.735***	36.678***	35.821***	36.072***	52.291***
		(6.610)	(7.358)	(7.204)	(7.211)	(10.006)
Fuel Cost				0.747***		0.729***
				(0.263)		(0.256)
Fuel Cost × Treatment					0.860***	
					(0.262)	
Fuel Cost × Control					0.512*	
					(0.287)	
Year FEs	X	X	X	X	X	X
Utility FEs	X	X	X	X	X	X
IV						X
Observations	2,595	3,229	2,595	2,595	2,595	2,593
R^2	0.59	0.60	0.61	0.62	0.63	0.62

Regressions are weighted by MWh purchased.

Cluster-robust standard errors are calculated at the utility level and displayed in parentheses.

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

assume that the distribution of types does not change in response to the prices.

Though upstream deregulation is correlated with higher prices in the time series, this correlation disappears (and becomes slightly negative) after controlling for downstream deregulation. The slightly negative coefficient is consistent with previous findings that upstream deregulation results in small efficiency gains (Fabrizio et al., 2007; Davis and Wolfram, 2012).

Table 3 presents our main regression results for the effect of deregulation on downstream prices. The estimated coefficients are similar to the estimated coefficients for upstream prices. In particular, the coefficient on downstream deregulation in model (4) of 43.518 is similar to the analogous coefficient of 35.821 for upstream prices.[10] The implied increase for the average downstream deregulation level of 0.43 is 18.7 $/MWh, or a 24 percent increase above a baseline downstream price of 77.1 $/MWh in 2000. The similar magnitudes for upstream and downstream prices suggest that the increase in retail prices was primarily driven by an increase in wholesale prices, and not by additional charges levied on downstream consumers.

One interesting difference is that the estimate of pass-through is higher for control states in the downstream market than in the upstream market. This may reflect the fact that the upstream prices reflect a small portion of electricity sold on the wholesale market, whereas the downstream market reflects the average cost borne by the regulated utility. Finally, we note that the differential coefficient on fuel costs in model (5) may be consistent with the presence

[10]The first-stage F-statistic in model (6) is 307.2.

Table 3: Dependent Variable: Downstream Prices ($/MWh)

	(1)	(2)	(3)	(4)	(5)	(6)
Upstream Deregulation	16.307***		1.304	−0.021	0.550	−3.922
	(3.085)		(3.714)	(3.426)	(3.401)	(4.045)
Downstream Deregulation		40.410***	42.319***	43.518***	42.935***	54.565***
		(8.571)	(8.670)	(8.657)	(8.688)	(8.440)
Fuel Cost				0.911***		0.919***
				(0.193)		(0.193)
Fuel Cost × Treatment					0.736***	
					(0.232)	
Fuel Cost × Control					1.053***	
					(0.156)	
Year FEs	X	X	X	X	X	X
Utility FEs	X	X	X	X	X	X
IV						X
Observations	2,627	3,274	2,627	2,627	2,627	2,625
R^2	0.89	0.90	0.90	0.91	0.91	0.91

Regressions are weighted by MWh purchased.

Cluster-robust standard errors are calculated at the utility level and displayed in parentheses.

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

of market power in the deregulated markets. Pass-through of fuel costs to retail prices appears to be lower for deregulated markets, which is consistent with the presence of market power.

3.4 Contract-Level analysis

In this section, we extend the previous utility-level analysis to contract-level data for all investor owned utilities. This sample includes wholesale level transactions reported to FERC in the Electric Quarterly Reports (EQRs) by the seller. Each observation includes the buyer, the seller, whether they are affiliated, the quantity, the price, and the terms of the contract under which each transaction took place. Though there are typically multiple transactions for each contract, we aggregate all transactions under a given contract in a year and compute the sum of the quantity traded and the average price weighted by quantity.

This sample only includes part of the transactions in spot market organized by ISOs. ISOs are not required to report sales of electricity that take place in the markets organized by them, so we do not observe these transactions in this dataset. We do observe transactions in which a company sells energy in the market organized by the ISO, since individual sellers are required to report. For the purpose of this analysis, this implies that we do not observe purchases from ISO markets by utilities in the EQR data, though from the Form 1 data we know how much the utility buys in these markets each year.

We start by estimating the impact of deregulation on contract prices using variations of the model in equation 2:

$$price_{it} = \beta^U E_{it}^U + \beta^D E_{it}^D + \gamma X_{it} + \xi_i + \phi_t + \varepsilon_{it} \tag{3}$$

As before, i indexes utilities and t indexes years, and we control for utility fixed effects (ξ_i) and yearly fixed effects (ϕ_t). E^U and E^D measure effective deregulation (the share of supply coming from independent companies) upstream and downstream, respectively. Thus, our coefficients of interest β^U and β^D capture the net effect of effective deregulation on prices.

We control for different sets of contract characteristics to account for differences in contract terms. These include transmission priority, the traded quantity in MWh, the number of consecutive hours to which the terms of the contract apply (e.g. weekly if the price does not vary in a week, hourly if it varies hourly), and whether the rate is subject to regulation (cost-based) or determined independently by the parties (market-based). Additionally, we control for the balancing authority containing the point of delivery, which indicates the area where the electricity is agreed to be delivered. Because transmission lines have limited capacity, transporting electricity is potentially expensive and this could be an important determinant of prices. Lastly, because the contract data does not include utilities' purchases from ISOs, we include the share of purchases from an ISO as a control, which we obtain from the FERC Form 1 data.

We include additional control to deal with some potential confounders. First, we include the log of carbon emissions in each state in 2005, when the Clean Air Act was enacted, interacted with a dummy for years after 2005. If environmental regulation was more expensive for deregulated states than for regulated states, we hope this variable to capture this effect. Secondly, we add the share of electricity produced by wind and solar in each state. All deregulated states and some regulated states have Renewable Portfolio Standards, which require that a minimum share of electricity comes from renewable sources. As this can potentially affect the cost of electricity, we control for the contemporaneous share of renewable generation in each state. We realize this strategy may not be enough and are working on a variable that accounts for the year in which the standards were approved in each state.

Finally, we instrument our effective downstream deregulation measure using the share of industrial and commercial customers. These segments are much more competitive than the residential sector, since industrial and commercial customers are more sensitive to prices. Therefore, markets with a lower share of residential customers are likely to be less competitive.

Table 4 presents our results for the effect of effective deregulation on contract prices. The dependent variable is the log of the average price paid in all transactions under a given contract, weighted by quantity. The coefficients represent the percentage change in price that is associated with a utility moving from no effective deregulation to full effective deregulation. In 2016, the average utility in this sample had effective upstream and downstream deregulation shares of 0.71 and 0.47, respectively. Thus, we can interpret the coefficients in our preferred

Table 4: Dependent Variable: Wholesale Contract Prices (log($/MWh))

	OLS				*IV*	
	(1)	(2)	(3)	(4)	(5)	(6)
Downstream dereg	0.823***	0.807***	0.738***	0.799***	1.200***	1.200
	(0.158)	(0.167)	(0.160)	(0.149)	(0.164)	(0.941)
Upstream dereg	0.067	0.054	0.053	0.087	0.049**	0.049
	(0.099)	(0.104)	(0.101)	(0.090)	(0.024)	(0.183)
Share ISO	0.051	−0.044	−0.041			
	(0.143)	(0.129)	(0.133)			
log(quantity)	−0.021***	−0.020***	−0.020***	−0.016***	−0.015***	−0.015***
	(0.004)	(0.004)	(0.004)	(0.004)	(0.001)	(0.005)
CO_2 05 CAA			−0.013	0.001	0.013**	0.013
			(0.019)	(0.019)	(0.006)	(0.034)
Share wind/solar			−0.653***	−0.733***	−0.472***	−0.472
			(0.191)	(0.256)	(0.131)	(0.686)
Constant	2.924***	2.141***	2.179***	2.951***	2.632***	2.632***
	(0.194)	(0.223)	(0.230)	(0.163)	(0.141)	(0.697)
Utility FE	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	Y	Y
BA FE	N	Y	Y	N	N	N
Contract chars	Y	Y	Y	N	N	N
Observations	72,718	71,921	71,921	72,763	72,763	72,763
R^2	0.519	0.547	0.548	0.512	0.511	0.511
Clustered SE	Y	Y	Y	Y	N	Y

Note: *p<0.1; **p<0.05; ***p<0.01

specification, (5), as follows: for the average utility, downstream deregulation was correlated with a 38% increase in prices, and upstream deregulation was correlated with a 4% increase in prices.

Instrumenting downstream competition does not change the coefficients much, but it is very imprecise, with standard errors so large that all coefficients are insignificant. This is likely due to the fact that the share of industrial and commercial customers does not change much over time, which combined with utility fixed effects leads to large standard errors since they are clustered at the utility level. Column (6) presents the results from the IV regression including robust standard errors that are not clustered.

The positive correlation between wholesale prices and downstream deregulation is consistent with what we found in the utility-level analysis of Section 3.3. The magnitude of the effect is smaller in the contract sample, potentially because we are only including a subset of utilities that does not include those in regulated states. Additionally, the contract data does not include MISO purchases. Though the utility-level does not show a significant correlation between upstream deregulation and wholesale prices, as we find with the contract data, we do find it between upstream deregulation and retail prices. Overall, our results point out to a tradeoff between efficiency gains and upward pressure on prices.

Our results are overall consistent with the idea that introducing competition upstream results efficiency gains that lead to lower prices, while downstream competition pushes wholesale prices upwards since it increases market power upstream and may introduce double marginalization. These mechanisms are discussed in more detail in the next section.

4 Discussion

Why did wholesale prices increase after deregulation? Below, we consider several potential explanations for the increase in prices. We find the presence of market power in the generation market to be an intuitive explanation for the price increases we observe.

Market Power and Double Marginalization

Prior to restructuring, electricity regulation was consumer-friendly, as utility-owned generators made zero profits on the generation of electricity and were reimbursed at average cost. Utilities could earn profits, but these profits were determined by a fixed rate of return on capital costs, based on investments in generation facilities, transmission lines, and the distribution grid.

Deregulation separated the upstream market from the downstream market, allowing generators to charge markups of price above cost to (previously integrated) retailers. Generator market power would produce positive markups in the wholesale market, with larger price increases arising from greater market power. We find this mechanism intuitive, and a number of papers in the literature provide evidence of market power in these markets (Borenstein et al., 2002; Wolak, 2003; Puller, 2007; Bushnell et al., 2008; Ito and Reguant, 2016).

Deregulation of the downstream market also allowed for retailers to earn markups above (increased) wholesale costs. Retail market power would increase markups over and above the level needed to recover fixed costs, causing prices to increase even more. Double marginalization results from the presence of markups in both the wholesale market and the retail market.

We want to highlight that this is not *just* a classic story of comparing double marginalization to the margins earned by vertically integrated entities. In the pre-deregulation regime, the vertically integrated utilities earned zero margins over the average (variable) cost.[11] Thus, the addition of both layers of markups could plausibly account for the large price increases we observe.

Empirically, we find that upstream prices and downstream prices increased by approximately the same magnitude. Thus, the price increases we observe are driven by larger markups upstream. As discussed above, wholesale prices could increase through the exercise of market

[11]Regulated utilities are allowed to earn margins high enough to pay a reasonable return on capital (fixed costs). If this charge is interpreted as the opportunity cost of capital, then prices are equal to average total costs.

power by generators. Market power was complemented by downstream deregulation, as the presence of competitive retailers provided generators with other customers beyond the regulated utility.

Our empirical findings suggest that changes in average markups in the downstream market were small. Downstream retailers in most states had to compete with the incumbent utility, who continued to sell electricity to consumers at (higher wholesale) cost. The presence of this option likely limited the degree to which competitive retail suppliers could raise prices.[12] Thus, the continued presence of a cost-of-service utility seems to have mitigated the increase in retail markups.

Finally, intermediate forms of vertical integration allow for another possible mechanism for price increases in the presence of retail market power. A downstream cost-of-service utility that shares the same parent company as an upstream generator has an incentive to "overpay" the affiliated generator for wholesale electricity. Higher prices to the generator result in higher profits for the parent company, as the utility's increased costs are passed on consumers. We examine this channel below.

Alternative Explanations

Marginal Cost versus Average Cost Pricing

Firms in competitive markets price based on marginal cost, rather than the average variable cost benchmark that utilities are reimbursed for (see Borenstein and Bushnell, 2015). Marginal costs are typically increasing, and, if higher than average variable costs, could further contribute to the price increases we observe.

We view this explanation as complementary to the market power mechanism discussed above, as it illustrates another effect of moving from a regulated regime to one with market-based pricing. Even if markets were perfectly competitive, we may observe a price increase arising from the switch from average-cost reimbursement to marginal-cost pricing.

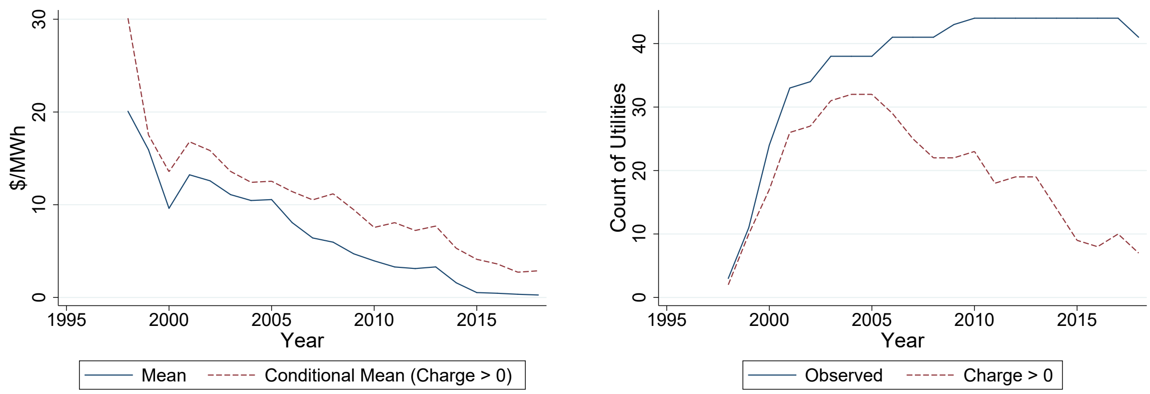
Transition Charges and Stranded Costs

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

We collected information on stranded costs for 44 large utilities across 16 states that were treated with deregulation measures. Most of the utilities for which we obtained data levied

[12] Competitive suppliers were able to enter and charge a margin by marketing a differentiated product or by timing their wholesale purchases to beat the utility's costs (Deryugina et al., 2019).

Figure 9: Transition Charges and Stranded Costs



(a) Mean Transition Charges

(b) Count in Sample

Notes: Data were collected from utilities and the relevant state regulatory commission.

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 9 shows the mean of these additional charges over time. This decline holds even if we condition the mean on utilities with positive stranded costs in each period, thus dropping utilities as their window for stranded cost recovery ends.

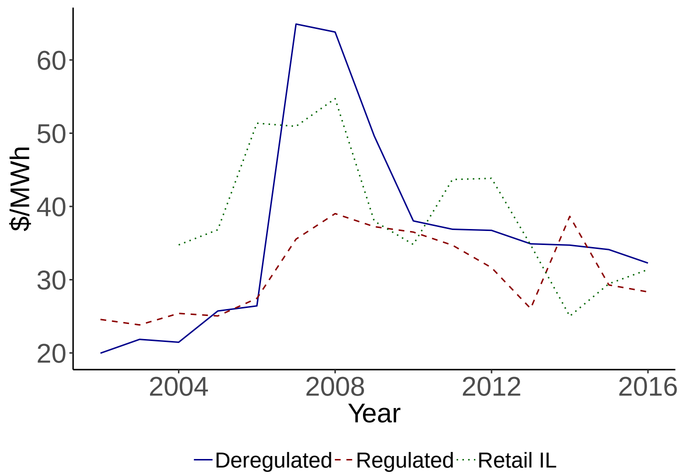
As shown in panel (b), individual utilities phase out stranded costs starting in 2006. The blue line shows the count of utilities for which we have stranded costs measures, and the red dashed line shows the count of utilities with positive costs.

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

Renewable Portfolio Standards

By 2009, all restructured states and some states that remained regulated had adopted renewable portfolio standards (RPS), which require utilities to procure a minimum share of the electricity sold from renewable sources. Since this has the potential to increase electricity costs (Greenstone et al., 2019) and the RPS were binding by the time we observe that prices increase, we would like to distinguish the effect of RPS on prices from that of restructuring itself. Though RPS are not necessarily related to retail competition, which we find is correlated to higher prices, it is in principle possible that the timing of RPS policies and of more intense retail competition coincides for some states.

Figure 10: Quantity Weighted Average Purchase Price



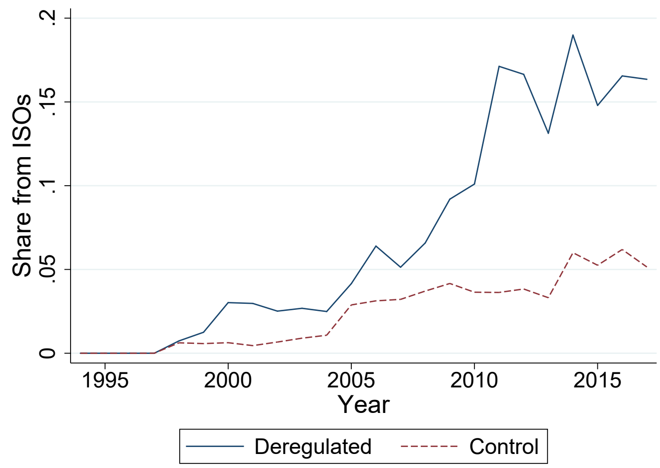
Notes: Regulated firms include all IOUs in Missouri and regulated utilities in Illinois. Only Illinois has deregulated utilities and retailers. Source: FERC EQR

In order to account for the potential effect of RPS, we control for either the share of generation coming from renewable sources (wind or solar), or the share of wind and solar in total capacity at the state level. Results with these controls for the contract-level data are reported in Table 4, and results using our aggregate data are reported in Tables 5 and 6 in the Appendix. RPS do not seem to be an important driver of price increases at the time retail competition increases, since estimated coefficients have the same signs and significance levels whether we include these controls or not.

Cream Skimming

Cream skimming could also explain why prices increase after effective deregulation, since the sample we use only includes the price paid by regulated utilities. If alternative retail suppliers attract the customers that are the cheapest to serve, the most expensive customers are left to the utility, therefore increasing its procurement costs. We explore this possibility for the case of Illinois and neighboring regulated states Iowa and Missouri using data on power sales from FERC Electric Quarterly Reports (EQR), which includes both incumbent utilities and competitive retailers as buyers. Figure 10 presents the evolution of prices paid by firms using this sample. The solid blue line shows prices paid by deregulated utilities, the dashed red line those paid by regulated utilities, and the dotted green line shows prices paid by retailers. We see from the figure that incumbents did not pay consistently more than competitive retailers, implying that cream skimming does not seem to be a plausible explanation for higher prices after deregulation. Though this sample does not include purchases from the spot markets organized by ISOs, the patterns are similar to those pictured by Figure 3, which suggests that the price differences are not driven by spot purchases.

Figure 11: Share of Purchases from ISOs



4.1 Vertical Integration and Market Power

Bushnell et al. (2008) study the interaction of vertical integration and market power in restructured electricity markets. They find that when firms are more vertically integrated, either formally or through long-term contracts, the respective wholesale market organized by the ISO is more competitive. The intuition behind this finding is that incentives to increase prices are more important for independent generators than for those integrated with the buyers.

Although our findings are related to those in Bushnell et al. (2008), we investigate changes in the prices paid by utilities in all their purchases instead of focusing only on the wholesale market organized by the ISO as they do. ISO purchases are part of these transactions, but results are unlikely to be driven by this component since it took years after the creation of ISO markets until utilities bought a significant part of their electricity from the wholesale market. This can be seen in Figure 11, where we plot the share of purchases from ISOs for investor owned utilities using data from FERC Form 1. In the latter years of the sample, ISO purchases constitute roughly 15 percent of the wholesale market in deregulated states. Thus, throughout our sample, the majority of energy is sold on contracts outside of the spot market.

4.2 Examining Transactions for the Case of Illinois

In this section, we go back to the case of Illinois using detailed transaction data from FERC Electric Quarterly Reports (EQR) to analyze the transactions that lead to price increases in more detail. EQRs are reports that all sellers of electricity at the wholesale level are required to submit, in which they describe the contractual terms of each transaction: purchasing firm, contract length, price, quantity, hours, location, and other characteristics of the agreement. This allows us to understand better what was behind the increase in prices that followed effective

Figure 12: Purchase Price by Affiliation

(a) Affiliated

(b) Unaffiliated

Notes: Source: FERC EQR

deregulation.

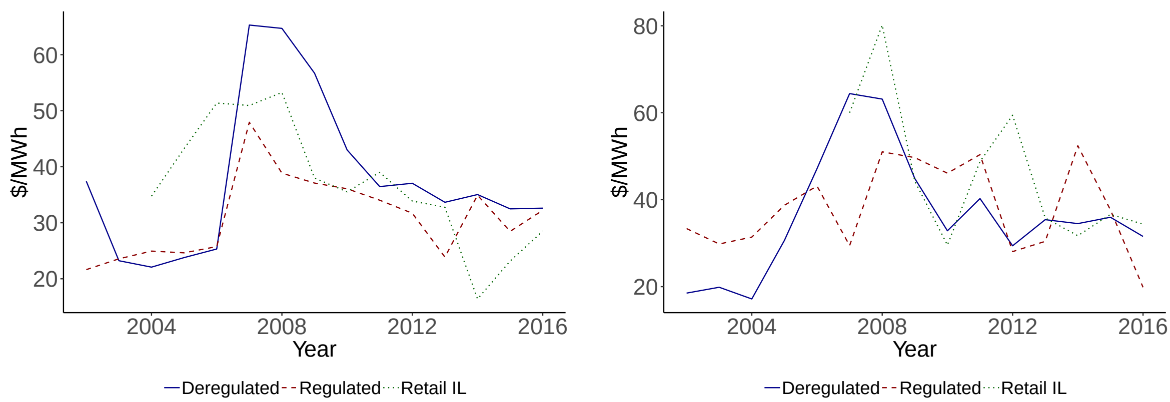
A first thing to notice is that higher prices came from purchases from affiliated sources. Figure 12 shows the evolution of the quantity weighted average price, but now splitting the sample between affiliated and unaffiliated purchases. The solid blue line shows prices paid by deregulated utilities, the dashed red line those paid by regulated utilities, and the dotted green line shows prices paid by retailers. Prices paid by deregulated utilities to affiliated sellers, presented in Panel (a), started similar to prices paid by regulated utilities, spiked in 2007 and then went down, but stayed higher than for regulated utilities until the end of the sample. Panel (b) shows prices paid in unaffiliated transactions, which stayed at similar levels for regulated and deregulated utilities with the exception of a spike in 2007 for deregulated firms, which is likely due to initial design and implementation issues with the procurement auction as explained above.

Second, higher prices are correlated to long-term contracts. Figure 13 also shows quantity weighted average price paid by utilities, but the sample is now split between long-term and short-term contracts, where short-term is defined as a year or less. This figure indicates that the higher prices paid after effective deregulation in 2007 came from long-term contracts, which increased in 2007 and remained higher than prices paid by regulated companies. By contrast, prices paid under short-term contracts stayed at similar levels during the whole period, with the exception of the spike of 2007.

In fact, we find that utilities in Illinois signed high price long-term contracts with affiliated generators in 2007, when many contracts expired and retail competition was introduced for all types of consumers. Utilities may have signed this contracts in an attempt to continue to delay effective deregulation, as they had done it until the moment.

Alternatively, these contracts may have been an attempt by utilities to shift profits upstream

Figure 13: Purchase Price by Contract Length



(a) Long term contracts

(b) Short-term contracts

Notes: Source: FERC EQR

to deregulated generation assets. As the incumbent utilities were still reimbursed at cost-of-service for any downstream customers, higher prices paid to generators would not affect downstream profits. However, generators were allowed to charge markups, so higher prices could increase upstream profits, especially as utilities face relatively inelastic retail demand. In this case, the parent company that owns both upstream and downstream entities would benefit. Thus, overpaying for electricity from affiliated generators may be a way for the downstream utilities to enhance the market power of the affiliated generator upstream.

5 Conclusion

We show that accounting for intermediate degrees of vertical integration—brought about by contracts and common ownership—is essential to analyze changes to market structure and the effect of market structure on prices. In the U.S. electricity sector, deregulation was effectively delayed for years by vertical arrangements that kept market structure similar to what it was before deregulation. When incumbents finally started to lose market share upstream and downstream, wholesale and retail prices increased. We argue that this was most likely due to the presence of market power in deregulated markets, compared to regulated markets where cost-of-service regulation effectively constrained prices.

First, upstream deregulation allowed generators to earn markups on supply, whereas regulated utilities were reimbursed at average costs and earned zero profits on electricity sold. Second, downstream deregulation introduced double marginalization and potentially increased market power upstream. Third, at least in the case of Illinois, it seems that firms attempted to use contracts with affiliated firms to exert market power and charge higher prices. These effects seem to have outweighed any generation efficiencies occurring upstream. One interpretation of our findings is that the regulation of electricity markets was consumer-friendly: consumers were paying for electricity at cost, and the (short-run) efficiency gains of introducing profit incentives to the generation market were modest.

When a regulator considers allowing for market-based prices, she faces the following trade-off: profit incentives may reduce costs through the more efficient allocation of resources, but the presence of market power may lead to increased markups. In the context of the deregulation of the U.S. electricity sector, we find that the increase in markups dominates despite modest efficiency gains, leading to higher prices to consumers. Our findings show that deregulation does not always lead to lower prices to consumers. A consumer-oriented regulator may prefer to regulate rates to be consumer friendly, rather than let prices be subject to market power.

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A Supplemental Tables and Figures

Table 5: Dependent Variable: Upstream Prices ($/MWh)

	(1)	(2)	(3)	(4)
Upstream Deregulation	-2.424	-1.527	-7.760^{**}	-6.682^{*}
	(3.124)	(3.115)	(3.687)	(3.645)
Downstream Deregulation	35.821^{***}	32.338^{***}	52.291^{***}	48.474^{***}
	(7.204)	(6.768)	(10.006)	(9.724)
Fuel Cost	0.747^{***}	0.746^{***}	0.729^{***}	0.748^{***}
	(0.263)	(0.237)	(0.256)	(0.234)
Share from Wind		-86.457^{***}		-67.361^{**}
		(27.380)		(28.590)
Share from Solar		31.925		51.364
		(156.683)		(150.784)
Year FEs	X	X	X	X
Utility FEs	X	X	X	X
IV			X	X
Observations	2,595	2,595	2,593	2,593
R^2	0.62	0.63	0.62	0.62

Regressions are weighted by MWh purchased.

Cluster-robust standard errors are calculated at the utility level and displayed in parentheses.

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 6: Dependent Variable: Downstream Prices ($/MWh)

	(1)	(2)	(3)	(4)
Upstream Deregulation	−0.021	−0.696	−3.922	−5.125
	(3.426)	(3.455)	(4.045)	(4.106)
Downstream Deregulation	43.518***	44.671***	54.565***	57.122***
	(8.657)	(8.859)	(8.440)	(8.585)
Fuel Cost	0.911***	1.045***	0.919***	1.060***
	(0.193)	(0.146)	(0.193)	(0.143)
Share from Wind		−0.341		6.173
		(21.847)		(22.196)
Share from Solar		321.927***		328.251***
		(121.447)		(115.841)
Year FEs	X	X	X	X
Utility FEs	X	X	X	X
IV			X	X
Observations	2,627	2,627	2,625	2,625
R^2	0.91	0.92	0.91	0.92

Regressions are weighted by MWh purchased.

Cluster-robust standard errors are calculated at the utility level and displayed in parentheses.

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$