Restructuring the Rate Base

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Abstract

Efforts to decarbonize the economy will depend on lowering electricity prices, which are now dominated by transmission & distribution (T&D) costs. Policies that focus on reducing generation costs may fail to lower electricity prices because regulated T&D utilities expand capital investments in response. As an episode of generation cost-reduction, this paper evaluates the impact of power plant divestiture on the restructured utilities whose operations became narrowed in scope following electricity market liberalization. These utilities' transmission and distribution (T&D) lines of business remained subject to cost-of-service regulation after their generation assets were sold off. I use a matched-difference-in-differences design based on proximate, similarly sized utilities not subject to restructuring reforms as a control group. I find that T&D utilities responded to restructuring by increasing regulated capital stocks downstream of the market reforms based on an annual panel of U.S. utilities' capital stocks from 1993-2009. Nine years after divestiture the average utility held an additional $0.45B (9.5%) of T&D capital. This finding suggests a mechanism through utilities prevent cost savings from being passed on to consumers.

JEL Classification: L50, L94, L98, P18, P51, Q40

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1 Introduction

As the costs of generation from renewables sources have plummeted, decarbonizing the U.S. economy requires electrifying end uses that have historically relied on hydrocarbons—heating and transportation in particular. Transitioning away from traditional fuel sources will depend on the purchase decisions made by households and businesses. The price of electricity is a key determinant of whether decarbonization goals will be met because it is a central element of electrification decisions (Davis (2021)). While subsidies for clean generation may help clean up the grid by supplanting fossil generation, they only help encourage electrification insofar as they are passed on to end use customers. How might regulatory dynamics in the setting of retail electricity prices affect the pass-through of generation cost shocks?

To answer this question I examine how utilities responded to the cost shocks that resulted from electricity market restructuring in the late 1990s and early 2000s. Research indicates that restructuring the U.S. electricity sector has yielded significant reductions in production cost. Deregulated power plants have been found to use less labor (Fabrizio et al. (2007)), less capital-intensive pollution abatement technology (Cicala (2015b); Fowlie (2010)), secure lower cost fuel (Chan et al. (2017); Cicala (2015b, 2021)), and reduce maintenance downtime (Davis and Wolfram (2012)). Wholesale markets are on one hand vulnerable to the exercise of market power (Borenstein et al. (2002); Mansur (2008)) but also promote trade across areas (Mansur and White (2012)). Cicala (2022) finds cost reductions dominate, on the order of \$3-5B per year in the areas that have adopted wholesale markets.

In spite of these cost reductions, there is no consensus that retail prices have fallen for customers (Bushnell et al. (2016); Joskow (2005); Kwoka (2008); Mackay and Mercadal (2021)). Where did the cost savings go, if not to consumers? Restructuring separated formerly vertically-integrated utilities into at least two prospective beneficiaries: deregulated generators, and regulated transmission and distribution (T&D) utilities.[1]

[1] A third prospective party would be competitive retailers who procure wholesale power and offer plans to final customers. Outside of Texas, this is overwhelmingly the same firm as the incumbent

In this paper I study one potential mechanism through which utilities facing restructuring might have prevented cost savings from making their way to consumers: by bulking up capital stocks in these downstream T&D operations that remained rate-regulated. During the rate-setting process, regulators add up variable costs and an allowed rate of return on the capital stock, or "rate base" to derive the utility's 'revenue requirement.' Dividing by expected quantities (more or less) yields the retail rate. If regulators focus on the nominal price of electricity as argued in Joskow (1974), T&D utilities may capitalize cost reductions into their rate base without increasing retail prices.

I test whether formerly vertically-integrated IOUs disproportionately increased their T&D capital stocks following power plant divestiture in the United States using an annual panel of utility assets collected by the Federal Energy Regulatory Commission (FERC) from 1993-2009. Following the estimation strategy of Cicala (2015b), I use a matched-difference-in-difference (DD) estimator to compare utilities with similar pre-divestiture capital stocks and in close geographic proximity. During the baseline period, the average utility held about \$6B in capital assets, half of which was in generation. I find that divestiture utilities on average held an additional \$0.45B in T&D assets nine years after divestiture relative to their predicted counterfactual. This represents a 9.5% increase over the counterfactual end-line, with most growth in capital occurring in the distribution system (\$0.4B per utility on average). This change takes the form of a steady and increasing rise in annual investments rather than a one-time jump in capital stocks. T&D investments were growing over time for all utilities, so the combination of industry trends and this additional capitalization means that divestiture utilities held nearly as much nominal aggregate capital in 2009 as they did in 1993, even though half of their regulatory assets had been sold off in the interim.

This finding has important implications for US decarbonization efforts. T&D costs have been growing while generation costs have fallen over the last decade, leaving the real price of electricity essentially flat (U.S Energy Information Administration

T&D utility, where the most popular 'default' rates remain regulated. Texas' T&D utilities are "wires only" and are prohibited from offering retail plans to final customers.

(2021)). Non-production costs now account for over half of the retail price of electricity. Because these costs are overwhelmingly recovered through volumetric rates, excessive T&D capital drives a wedge between retail prices and the social marginal cost of electricity (Borenstein and Bushnell (2021, 2022)). Higher retail prices then deter investments to electrify buildings and transportation. There is scant research on utility T&D investment in spite of its now-dominant role for retail electricity pricing.

A few caveats are in order. First, it is difficult to make claims regarding the welfare effects of excess T&D investment. This will depend upon whether utilities are making system upgrades that consumers value, or are overpaying for equipment that sits unused in warehouses (Fendt (2021)). The goal here is to explore a potential mechanism that would explain why consumer prices have not fallen rather than conduct a comprehensive welfare and distributional analysis of restructuring. Second, I do not observe power purchase agreements, and do not estimate the share of production cost savings that deregulated generators kept for themselves. Third, the analysis is necessarily conducted at the utility- rather than plant-level. After matching plants of similar vintages, location, and fuel inputs there is relatively limited room for unobserved confounders to degrade the credibility of the analysis. Utility service territories, however, may remain heterogeneous after matching on capital stocks and proximity. With only 123 total utilities (44 divested) in a diverse country, there is only so much one can do to construct credible counterfactuals. I find estimates that are generally stable across matching specifications, but nonetheless caution that these results are more akin to analyses conducted with (matched) state-level panels than plant-level micro-data.

This paper is structured as follows: in the next section I provide more detail on the various regulatory changes that occurred in the U.S. electricity sector, in the third section I describe the data, and the fourth section develops the estimation strategy. The fifth section presents the results and the final section concludes.

2 Background on Utility Regulation in the United States

The electricity sector was highly fragmented in its early days, with different companies and incompatible networks springing up to serve myriad functions (lighting, appliances, trolleys, etc.) all separately. With the adoption of alternating current and centralized power stations, economies of scale strongly favored consolidation. In the hands of a private company, the vertically-integrated investor-owned utility (IOU) was born. These companies held monopoly franchises to operate in designated territories and submitted to regulatory oversight from public utility commissions. In various parts of the country the IOU model never took hold, and instead the local municipality operated the electricity system (as with many water systems). Alternatively the state or Federal government would operate the bulk system and sell power to local cooperatives. Some of these local cooperatives would themselves own power plants as well—operationally but not economically structured much like IOUs.

As described in Cicala (2015b) and elsewhere, the process of setting regulated prices largely entails dividing 'required revenue' (i.e. costs) by anticipated sales during a rate hearing. During the rate hearing process, the regulator would audit historical accounts from the utility during a 'reference year' that would serve as the representative basis for rate setting. Total allowed revenue is the sum of non-capital costs (V) and an allowed rate of return (s) on the utility's capital stock, or "rate base" (K). Selling Q MWh of electricity yields the retail price

$$p = \frac{V + sK}{Q} \quad (1)$$

Aside from prospective automatic adjustments for fuel prices, the price p would be fixed for some period of time until the subsequent rate hearing, which might be requested by either the utility or consumer advocacy groups if there were sufficiently large changes in fundamentals that required an update. Thus the utility might actually be the residual claimant in short-term cost savings realized during the periods between rate cases, and any 'rate of return' might prevail during this interim (Joskow (1974)). The focus on regulated utility overcapitalization comes from the observation that s is often greater than the utility's cost of capital (Averch and Johnson (1962); Baumol and Klevorick (1970)). While non-capital costs are passed through one-for-one, utilities earn a margin on every dollar of capital invested. When approving capital investments, the regulator locks in long-term earnings for the utility in spite of whatever short-run fluctuations might be realized between rate cases.

State-led restructuring initiatives proliferated in the 1990s amidst a general shift in attitudes favoring deregulation. Encouraged by the recognition that generation was not a natural monopoly on an interconnected grid (Joskow and Schmalensee (1983)), these policies were more likely to be adopted in places with large differences in prices between wholesale and retail rates (White (1996)). What is often called "deregulation" actually refers to a suite of different policies that may or may not have been enacted in various jurisdictions.

On the generation side, state-mandated power plant divestiture required IOUs to sell their generation assets to deregulated firms or affiliates (Cicala (2015b)). Transmission has largely remained regulated everywhere, though independent system operators (ISOs) have taken over determining which power plants operate using wholesale electricity markets (see Cicala (2022) and citations therein). Note that wholesale markets are distinct from state-led restructuring policy, so that large parts of the country remain entirely rate-regulated even though wholesale markets determine their power plants' operations.[2]

"Retail choice" is perhaps the most confusing of the restructuring policies, as it creates the appearance of competition for customers. Yet local distribution continues to be operated by regulated monopolies everywhere, regardless of other deregulatory initiatives. Instead, retail choice introduced competition in procurement for the energy portion of customers' bills without any change in the regulation or operations of electricity distribution. For example, before retail choice Commonwealth Edison (ComEd) owned the distribution system and sent bills to customers as determined by

[2]Only Illinois utilities are restructured in the footprint of the Midcontinent Independent System Operator (MISO). The Southwest Power Pool (SPP) serves only traditional providers (IOUs, Cooperatives, etc.). These utilities' plants bid into wholesale markets, and are called on to operate when economical. Net revenues from market operations are accounted for in the traditional ratemaking process.

the Illinois Commerce Commission. After retail choice, ComEd continued to own and operate the distribution for *all* customers, but alternative suppliers might recruit customers away from the incumbent with preferable terms for the energy supply portion of their bill (Deryugina et al. (2020)). Competitive retailers might also differentiate themselves by procuring renewable energy or offering rate structures that smooth bills, float with wholesale prices, etc. These activities are executed through financial arrangements, so these services do not actually touch any wires. When the lights go out, customers call the legacy T&D utility regardless of whether the energy portion of their bill is with a legacy utility or competitive retailer. In short, physical T&D operations have remained universally rate-regulated.

Only Texas *requires* customers to choose a retailer; retail choice is an *option* in other restructured states that exists alongside a default plan offered by the legacy utility at a regulated rate. The rather convoluted structure of retail choice combined with consumer inertia means that legacy utilities have retained the overwhelming majority of customers eligible to select competitive suppliers (Energy Information Administration (2018)). The upshot is that the regulated rate hearing process and the incentives described by Joskow (1974) remain front-and-center, even in restructured states.

When regulators are more sensitive to realized price increases than foregone savings, cost reductions present utilities with an opportunity. Increasing the rate base when costs are falling allows utilities to capitalize the savings into a regular flow of payments. Larger T&D capital stocks would provide an explanation for why retail prices have not fallen to reflect lower generation costs after restructuring. Two other forces pushing in this direction are also worth mentioning. First, the formerly-vertically integrated IOUs that sold off their generation to unaffiliated companies suddenly found themselves with liquid assets seeking a regulated rate of return. Second, restructuring narrowed investment opportunities to the T&D rate base so a target level of earnings could only be achieved with higher T&D investment. I view these as complementary, rather than competing explanations for higher T&D capital stocks following restructuring. The key point is that each of these reasons for greater T&D capital persist in spite of the fact that T&D rate regulation was itself unchanged between restructured and vertically-integrated utilities.

Analysis of the impacts of divestiture policy on distribution systems is thin. Kwoka et al. (2008) find distribution systems become less productive after divestiture, but do not include capital assets in their analysis. This is a rather severe limitation given the overwhelmingly fixed nature of distribution system costs.

3 Data

The main data source of this analysis is the FERC Form 1 - Electric Utility Annual Report. These are comprehensive financial reports filed by major utilities operating under FERC jurisdiction. Filings are available in electronic form back to 1994 and are extracted from their legacy database format by the Public Utility Data Liberation (PUDL) Project.[3] These sprawling reports include detailed accounts of utility capital stocks broken down into asset categories so that generation, transmission, distribution, and miscellaneous equipment are recorded separately.

I identify 123 FERC-reporting utilities serving end-use customers that owned generation, transmission, and distribution assets before 1997. Of these, 44 would eventually divest some or all of their generation assets as part of state-mandated electricity restructuring policies. In cases where the restructured utility becomes a new wires-only FERC-reporting entity, I connect reports to the legacy utility to create a nearly-balanced panel from 1993-2009. Following Cicala (2015b) the sample period ends in 2009, though the reasoning differs somewhat: while both studies are interested in credibly-estimating the short- and medium-run impacts of restructuring policy, there are two additional events that motivate the sample window here. First, the American Recovery and Reinvestment Act of 2009 brought an influx of grants and favorable tax treatment for smart meters and other 'smart grid' investments. Second, natural gas prices fell in 2009, beginning an extended period of historically-low prices maintained by the fracking revolution (Hausman and Kellogg (2015)). Lower input costs may have also created space for gas-intensive utilities to make capital investments without

[3]The reports include both start- and end-of-year totals, so data are technically available going back to the end of 1993 (i.e. the start of year figures in 1994).

raising nominal prices. Both of these events introduce confounding treatments.

The process of generation divestiture can be seen in aggregate in Figure 1(A), which plots nominal generation assets separately for utilities that would eventually be restructured ("divestiture utilities"), and utilities that would retain their traditional structure ("traditional utilities"). Leading up to 1997 there were roughly $300B in total generation assets, evenly split between divestiture and traditional utilities. By 2002 all but about $25B of the initial $150B in power plants owned by divestiture utilities would be sold to unregulated firms or affiliates.[4] From 1997-2009, regulated utilities continued to build and own new power plants, accumulating nearly $100B in additional capital (a 67% increase). Of course new power plants were also constructed to serve customers in restructured territories, but those deregulated assets are outside of FERC's Form 1 data collection.

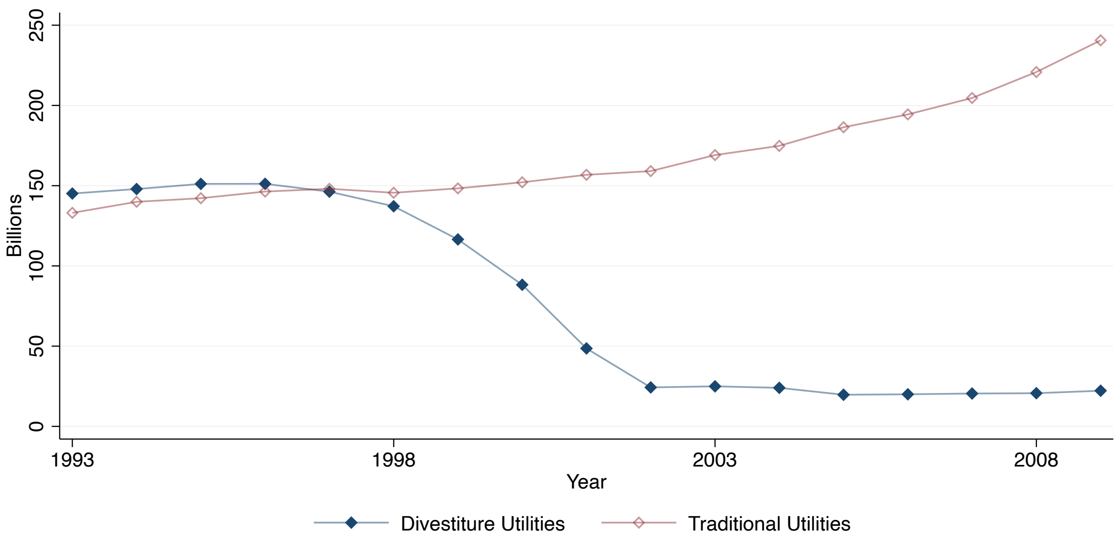
Figure 1(B) plots the nominal aggregate utility capital stocks by eventual divestiture status, including generation, transmission, distribution, and miscellaneous assets. In the early 1990s, vertically-integrated utilities reported assets worth roughly one half of a trillion dollars. Total assets were also evenly split between divestiture and traditional utilities. Total assets owned by divestiture utilities declined during the divestiture period from 1997-2002. After bottoming out, however, transmission and distribution assets at divestiture utilities grew so that they owned as much nominal capital in 2009 as they did in 1993, but without power plants.

Table 1 presents summary statistics of utility profiles in 1997 by divestiture status. While aggregate total assets are evenly divided between divestiture and traditional utilities, there were fewer divestiture utilities and so their portfolios tended to be larger on average. In addition to having more assets, they served more customers, and sold more power. Combining this larger volume with higher prices meant that the average divestiture utility earned nearly $1B/year more in revenue than the average traditional utility (double).

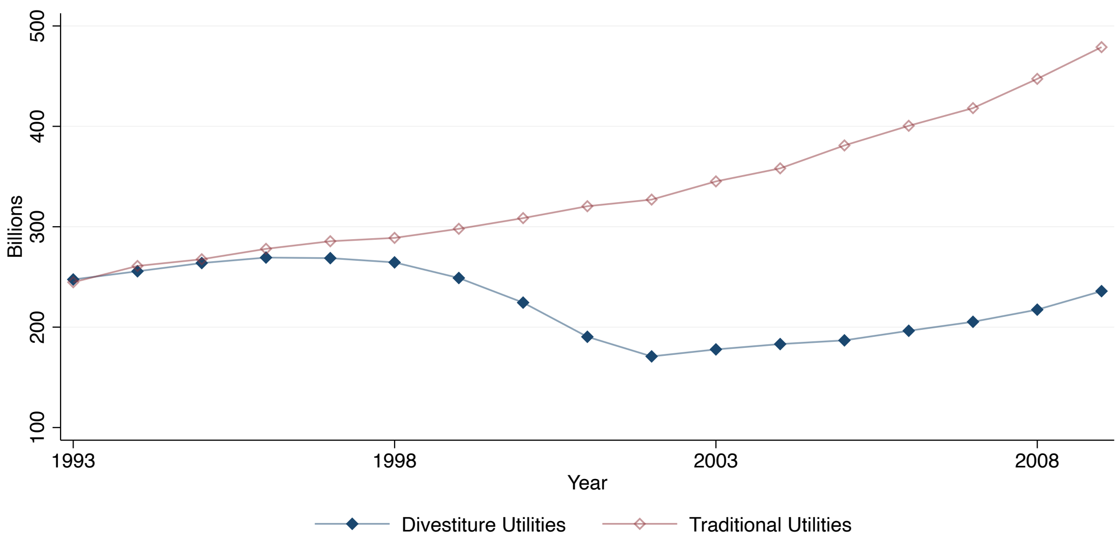
[4]California froze its divestiture policy after a few billion in generation assets had already been sold, accounting for much of the generation capital remaining on divestiture utilities' ledgers. Results are robust to excluding California from the analysis.

Figure 1: Aggregate Electric Utility Capital 1993-2009

(A) Generation Capital



(B) Total Utility Capital



Note: Data come from FERC Form 1. Totals are calculated for utilities that generated, transmitted, and distributed power to end-use customers in 1997. Linkages were made to follow regulated distribution utilities after restructuring, but generation assets are no longer reported following divestiture.

Table 1: Electric Utility Summary Statistics in 1997

	All Utilities			Matched Utilities		
	Divested	Not Divested	Difference of Means	Divested	Not Divested	Difference of Means
A. Assets (Billion $)						
Total Capital	6.11	3.62	2.49**	6.55	5.04	1.51
	[6.65]	[3.95]	(1.09)	[6.68]	[4.08]	(1.31)
Production	3.32	1.87	1.45**	3.57	2.67	0.89
	[4.03]	[2.17]	(0.65)	[4.07]	[2.33]	(0.78)
Transmission	0.63	0.47	0.16	0.68	0.68	–0.00
	[0.70]	[0.47]	(0.12)	[0.70]	[0.45]	(0.14)
Distribution	1.89	1.07	0.81**	2.02	1.45	0.58
	[2.13]	[1.16]	(0.35)	[2.15]	[1.18]	(0.41)
Other	0.26	0.20	0.06	0.27	0.24	0.03
	[0.34]	[0.28]	(0.06)	[0.34]	[0.30]	(0.08)
B. Generation and Sales						
Capacity (GW)	5.23	4.26	0.97	5.61	6.33	–0.72
	[5.95]	[4.68]	(1.04)	[5.99]	[4.76]	(1.31)
Sales (TWh)	21.70	16.50	5.20	23.26	23.95	–0.69
	[22.90]	[16.64]	(3.92)	[22.96]	[16.82]	(4.92)
Revenue ($	1.88	0.98	0.90***	2.02	1.37	0.65*
B)	[1.99]	[1.07]	(0.32)	[1.99]	[1.01]	(0.37)
C. Prices ($ / kWh)						
Residential	0.11	0.08	0.03***	0.11	0.08	0.03***
	[0.02]	[0.02]	(0.00)	[0.02]	[0.02]	(0.01)
Commercial	0.09	0.07	0.03***	0.09	0.07	0.02***
	[0.02]	[0.02]	(0.00)	[0.02]	[0.02]	(0.01)
Industrial	0.06	0.04	0.02***	0.06	0.05	0.02***
	[0.02]	[0.01]	(0.00)	[0.02]	[0.02]	(0.00)
D. Share of Sales						
Residential	0.32	0.32	0.01	0.33	0.31	0.01
	[0.05]	[0.09]	(0.01)	[0.05]	[0.06]	(0.02)
Commercial	0.34	0.29	0.05**	0.34	0.27	0.07***
	[0.12]	[0.10]	(0.02)	[0.12]	[0.09]	(0.03)
Industrial	0.32	0.37	–0.05*	0.31	0.39	–0.08**
	[0.13]	[0.18]	(0.03)	[0.13]	[0.14]	(0.04)
Utilities	44	79	123	41	44	85

Note: Data from non-divestiture utilities in the matched sample receive weight $\frac{1}{m_j}$ for each matched divestiture utility. Matching criterion: Nearest five utilities based on mean total capital stock between 1993 and 1997 and within 500 miles. Standard errors are clustered by utility in parentheses, and standard deviations are in brackets.
* p<0.1, ** p<0.05, *** p<0.01

4 Estimation Strategy

The strategy to estimate the impact of power plant divestiture on IOU ownership of non-generation capital closely follows that of Cicala (2015b), which is based on a matched-differences-in-differences design (matched DD). In a traditional DD, the mean (residual) change in outcomes for the control group serves as the counterfactual for what would have occurred in the treatment group in the absence of treatment. This permits the estimation of causal impacts between two groups that may be different from one another in levels, so long as their paths would have otherwise been parallel. Matched DD adds an additional dimension of flexibility by weighting units in the control group to establish conditional independence of treatment (Heckman et al. (1998)). Thus it may be the case that treatment and control groups are unconditionally diverging over time, but the control units that are actually used to estimate counterfactuals are those whose paths closely mirror the path that would have been followed by treatment units in the absence of treatment.

Figure 2 maps the approximate service territories of utilities in the United States based on counties. As motivated in Cicala (2015b), the spatial distribution of divestiture is not random, so it is potentially problematic to simply consider the relative change in outcomes between divestiture and traditional utilities. This would be a problem for traditional DD designs if regions were following different paths over time. The matched DD approach of Cicala (2015b) effectively ignores the outcomes at power plants far from divestiture, and considers plants in close geographic proximity so that divestiture and traditional plants have similar fuel purchasing opportunities. This allows for time-varying local shocks that would have confounded a standard DD design.

Here the data are measured at the utility-year instead of power plant-month. While traditional DD can account for time-invariant differences between these groups, there may also be diverging trends between regions that affect utility capital needs (population growth, density, local labor markets, etc.), as well as time-varying differences between large and small utilities. Failing to account for such non-random assignment of treatment would bias estimates of the causal impact of divestiture.

To account for both spatially-correlated and size-determined sources of time-varying unobservables, I alternatively match utilities based on the proximity of borders (within 100 or 300 miles), or within 500 miles and based on the total capital stock reported by utilities averaged between 1993-1997, the final year before any divestitures began. I also control directly for annual load, though results for capital stocks are similar without this additional control. Geographically, this means matches for New England states focus on Vermont and New Hampshire, Mid-Atlantic states match with utilities in Virginia, North Carolina, and Ohio, and divestiture utilities in California, Texas, and Illinois match with traditional utilities in the surrounding areas.

As shown in Figure 2, utilities on the diagonal between Florida and Washington states are typically omitted from matched specifications. Note that utilities whose power tends to come from federally-administered generation (i.e. Tennessee Valley Authority and U.S. Bureau of Reclamation) are not reported in the FERC data. In total there are 44 divestiture utilities, 41 with borders within 300 miles of a traditional utility service area. There are 50 traditional utilities whose borders are within 500 miles of a divestiture utility.

Within distance bands, matching based on total capital stocks during the baseline period ensures that utilities being compared are of comparable size. This means, for example, that a small Vermont utility may serve as a counterfactual for a similarly-sized rural upstate New York or Massachusetts utility, but is not standing in for the changes that would have occurred in New York City.

I define treatment as the first year after power plant divestiture begins, which introduces some attenuation in the early years for utilities whose sales were staggered over time.[5] Data on divestiture status come from Cicala (2015a), and are constructed from filings with the Energy Information Administration (EIA).

The effect of matching on the mean differences between divestiture and traditional utilities can be seen in the right panel of Table 1. The difference in total capital falls by about $1B per utility, with reductions in the baseline difference in each asset category. The matched utilities

[5]The average divestiture utility sold off 70% of its generation assets in the first year.

are much more similar in their sales volumes, though divestiture utilities continue to have higher prices across all customer classes, and therefore earn modestly higher revenues. This is consistent with the observation that 'price gaps' motivated the adoption of restructuring policies (White (1996)).

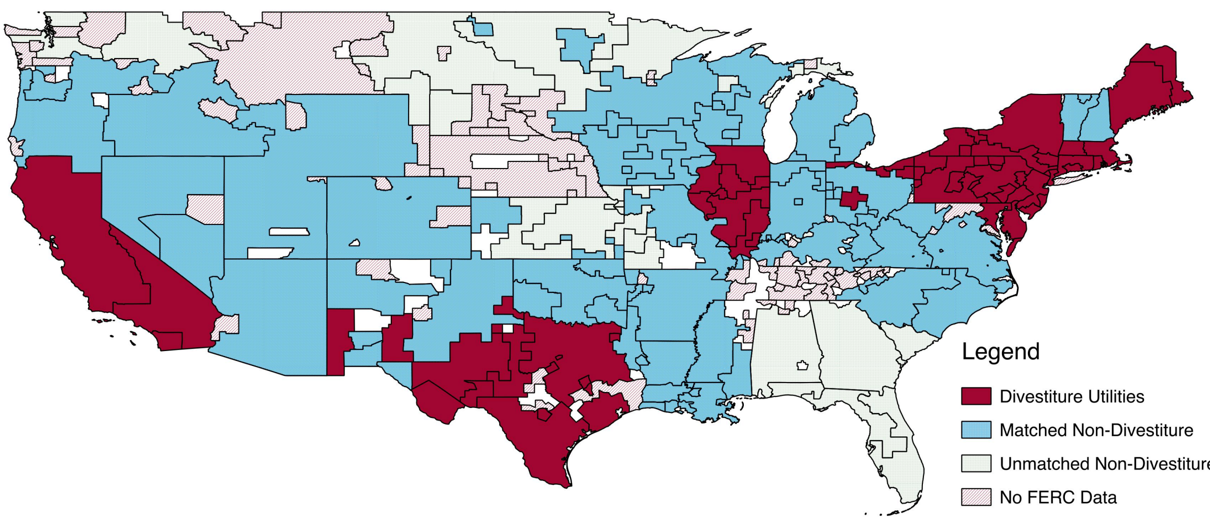
That utilities with the largest potential cost savings selected into restructuring is a problem for external, but not necessarily internal validity. If the construction of counterfactuals for treated utilities is sound, this approach delivers an estimate of "treatment on the treated," i.e. the impact of divestiture on those utilities that were restructured. This is more restricted than an overall "average treatment effect," which requires that the same impact would have been observed if restructuring policy were universally applied. I do not make this latter assumption, and interpret my results as the impact of restructuring on the restructured utilities.

I estimate difference-in-differences (DD) models of the form

$$y_{it} = D_{it}\tau + X_{it}\beta + \gamma_i + \delta_t + \varepsilon_{it} \tag{2}$$

where y_{it} is the outcome of interest for utility i in year t, γ_i and δ_t are utility and year fixed effects, respectively, X_{it} represents annual load, and D_{it} is an indicator that turns on after utility i begins to divest its power plant holdings. When using matched-DD specifications, control observations are weighted in proportion to the role they play in constructing counterfactuals for various treated facilities (matching is conducted with replacement). In event study-type figures I expand τD_{it} to be a comprehensive sequence of indicator variables in 'event time', so that $\tau_p \chi(r_{it} = p)$ measures the relative difference in outcomes at divested utilities in year p relative to the onset of divestiture. The year prior to first divestitures ($p = 0$), is omitted as a normalization to complete the DD interpretation. Regarding inference, I cluster standard errors at the utility level.

Figure 2: Utility Service Areas in the United States by Generation Divestiture Policy



Note: Service areas are approximate, based on FIPS counties reported in EIA-861 in 1999. Some territories are disjointed, but served by a single reporting utility. Matched non-divestiture utility borders are within 300 miles of the border of a divestiture utility.

5 Results

Figures 3 and 4 present the main results as event study figures. All outcomes are measured in levels to facilitate adding up across asset categories. I plot results for four years prior to divestiture and nine years after, as differences in the timing of divestiture create substantial compositional changes in the sample: There are a limited number of utilities that had already been divested for ten years by 2009, for example. The results presented here are based on matching the 5 most similar utilities based on initial capital stocks, within 500 miles. The analogous figures without matching (i.e. unweighted DD) are presented in Appendix Figures A.1 and A.2.

In Figure 3(A) we see that the initial impact of divestiture is a nearly \$1.5B reduction in production capital. This effect grows over time for a couple of reasons: First, as mentioned earlier, treatment is defined as the first year of divestiture, and some sales occurred in subsequent years. Second, as indicated in Figure 1(A), divestitures were not reversed, so all growth in generation capital in traditional utilities shows up as a relative decline. Nine years after onset the average divestiture utility owns about \$4B less in production capital than predicted in the absence of restructuring.

Though the pre-trends and initial change for total utility capital (Figure 1(B)) are identical to those of production capital, the relative declines in subsequent years are less steep. This indicates that relative growth is occurring in the non-generation asset categories. We get a sense of the total magnitude of this relative growth by comparing the $\sim$\$4B relative drop in production capital with the $\sim$\$3.5B drop to total capital overall.

Figure 4 shows that the gap between total and production capital paths can be largely explained by an expansion in distribution capital. The pre-trend for distribution was flat leading up to divestiture, so that capital stocks were growing in parallel with traditional utilities. The distribution capital stock begins to bend a year after divestiture, indicating a change in net investment. This relative growth in distribution capital grows steadily throughout the post-divestiture period, arriving at \$0.4B per utility in the ninth year after initial divestitures.

For transmission capital, it appears that divestiture utilities were growing less slowly prior to divestiture. This differential trend does not appear when estimating equation (2) without controls for annual load, which means that divestiture utilities were not keeping up with transmission capital per MWh delivered, even though their nominal capital investments were equal. Consistent with transmission investments requiring time to get going, there is a reversal in this relative trend two years after initial divestitures. At end-line there is about \$50M in extra transmission capital, which could perhaps be more like \$100M if one thinks the appropriate 'onset' of treatment actually occurred with a lag.

Combining the relative growth in T&D capital there is about ∼\$0.45B extra per divestiture utility nine years after divestiture. This adds up to the aggregate total deduced from Figure 1. Supposing T&D assets grew in parallel with traditionally regulated utilities, divestiture utilities would have held an average of \$4.7B in T&D capital. Thus the increased capital accumulation amounts to excess of about 9.5% at end-line.

Each of the outcomes evaluated to this point are capital stocks that accumulate the sequence of historical investment, divestment, and depreciation decisions. With stocks as outcomes, a one-time shock to flows appears as a break (i.e. production capital divestiture), while a permanent change in investment appears as a bend (i.e. distribution capital growth). I alternatively evaluate flows instead of stocks, considering net capital investment (i.e. the year-to-year change in capital stocks). Appendix Figures A.3 and A.4 plot the event study paths of net investment over time, and reveal the distinction between one-time shocks and persistent breaks in annual investments.

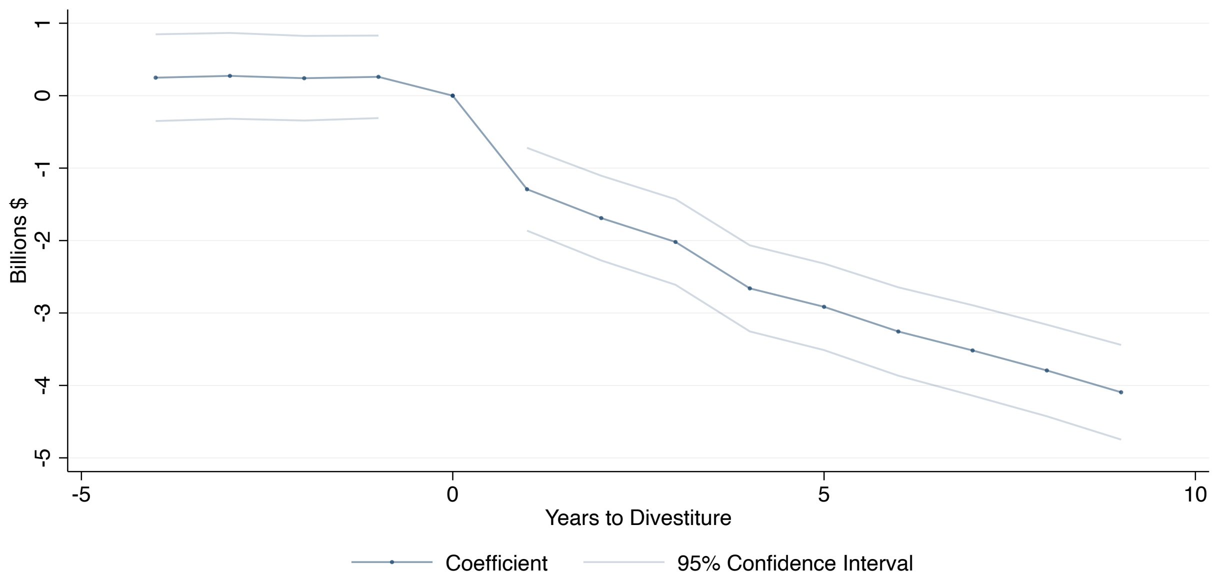
Table 2 presents regression results using net investment in each asset class as the outcome variable (in billions of dollars). It measures a single post-divestiture treatment effect as in equation (2), and represents the average change in annual net investment due to divestiture policy. The first column presents unweighted DD results including data from all utilities. Columns (2) and (3) include all utilities whose borders are within the specified distance band. Each divestiture utility receives a weight of one if there are any traditional utilities within the specified distance, and zero otherwise. Each traditional utility receives a weight equal to the sum of its match weight across divestiture utilities. Columns (4) and (5) use a 500 mile distance band as an initial filter, but then match the m closest utilities based on total capital, averaged between 1993-1997.

The difference between total net investment and production net investment yields about a \$30M gap per year. When measuring single post-divestiture coefficients, this appears to be driven entirely by distribution system investments, but the relative trend in pre-period capital for transmission observed in Figure 4(B) indicates the impact on transmission investment might be modestly under-estimated with this approach. Appendix Figure A.4 presents the event study figures for T&D net investment (i.e. flows) that are analogous to the capital stocks presented in Figure 4. For distribution, the level shift in investment indeed tracks the accumulating bend in stocks observed earlier. The change in investments is not statistically significant year-by-year in the event study figure, and as a single coefficient it is significant at the 10% level. That said, the persistence of the change means that distribution capital continued to grow, so that at end-line the differential capital stock has a p-value of 0.005. This is an excess capital stock that is both economically and statistically significant.

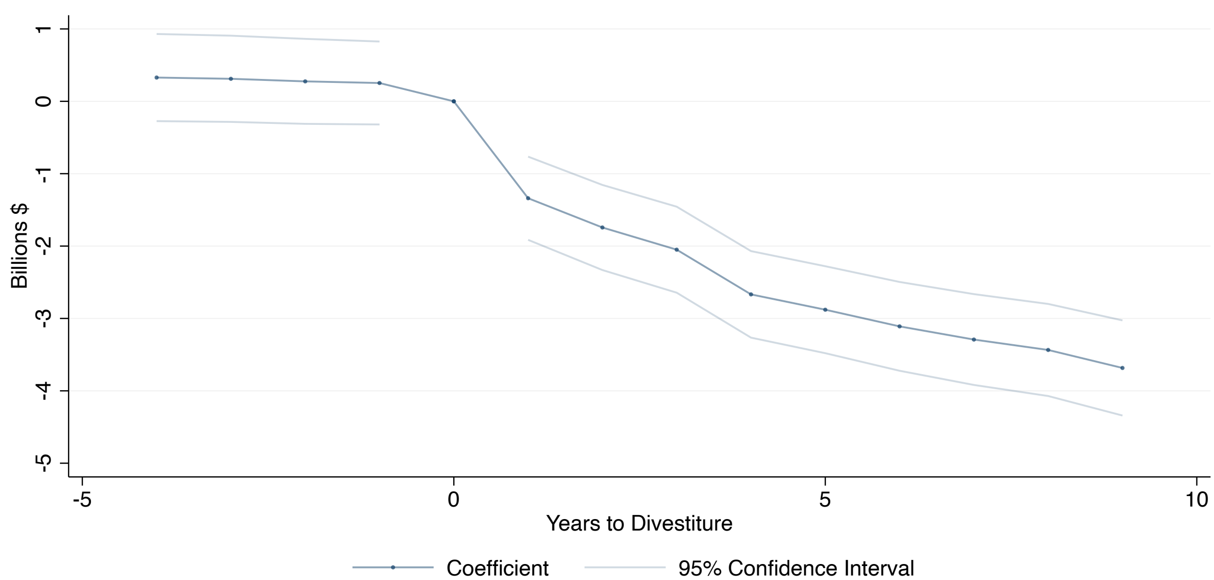
Looking across columns of Table 2, it appears that matching yields small changes in the estimates. Each of these columns represent specifications designed to account for different types of unobserved confounders. The first column controls for time-invariant differences between utilities, and uniformly accounts for changes over time. These estimates would be biased if there were an unrelated determinant of capital stocks that was correlated with divestiture, differentially changing over time. The second two columns allow for such differential changes that might be occurring in a spatially-correlated manner: population growth, input prices, regional development, etc. The final two columns further allow for such shocks to be specific to the size of utilities: small utilities in the northeast might be subject to different shocks from large utilities in the northeast, for example. All estimates include controls for annual load served. The fact that estimates are so similar across columns indicates that these types of unobservables are not meaningfully confounding estimates. This cannot entirely rule out the possibility of omitted variables bias, but severely limits the nature of what such a variable might be: correlated with divestiture and changing over time specifically at divestiture utilities, but not their similarly-size neighbors.

Figure 3: Matched DD Estimates by Year to First Divestiture: Total and Production Capital

(A) Production Capital



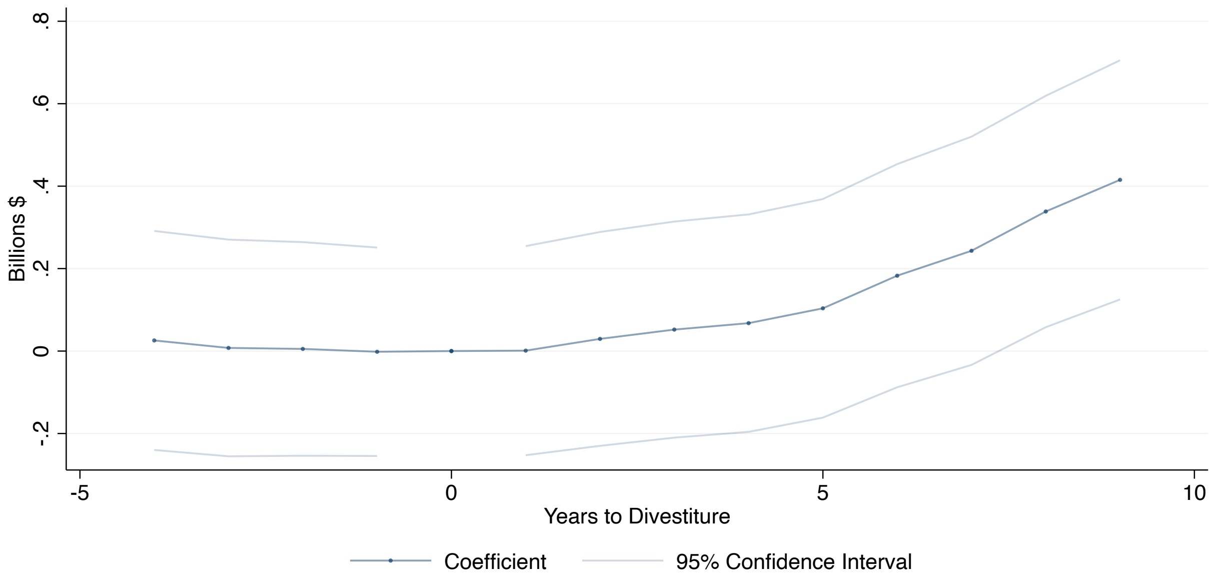
(B) Total Capital



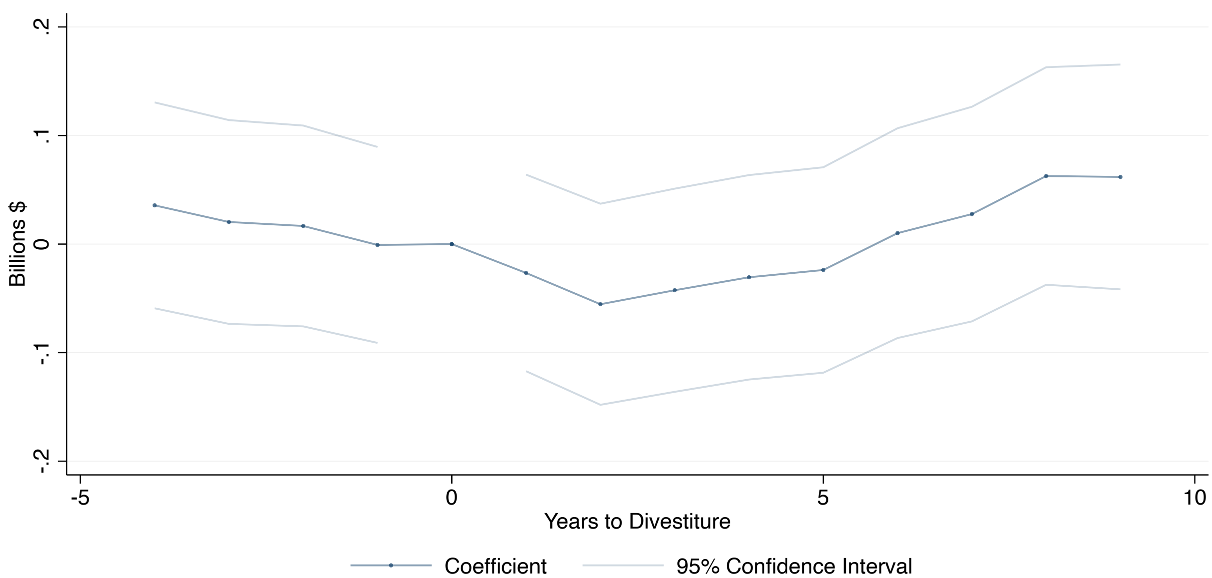
Note: Matching criterion: Nearest five utilities based on mean total capital stock between 1993 and 1997 and within 500 miles. Standard errors are clustered by utility.

Figure 4: Matched DD Estimates by Year to First Divestiture: Distribution and Transmission Capital

(A) Distribution Capital



(B) Transmission Capital



Note: Matching criterion: Nearest five utilities based on mean total capital stock between 1993 and 1997 and within 500 miles. Standard errors are clustered by utility.

Table 2: Effects of Divestiture on Net Investment by Capital Type

A. Distribution Net Investment ($ B)

	(1)	(2)	(3)	(4)	(5)
Post-Divest	0.032**	0.033*	0.031*	0.027	0.029*
	(0.016)	(0.020)	(0.017)	(0.017)	(0.017)
m nearest neighbors	–	–	–	1	5
Proximity Threshold (mi.)	–	100	300	–	–
Utilities	123	75	91	64	85
Divested Utilities	44	35	41	41	41
R^2	0.462	0.441	0.445	0.412	0.435
Obs.	1953	1192	1447	1002	1350

B. Transmission Net Investment ($ B)

	(1)	(2)	(3)	(4)	(5)
Post-Divest	0.012	0.003	0.006	0.009	0.004
	(0.009)	(0.013)	(0.010)	(0.011)	(0.010)
m nearest neighbors	–	–	–	1	5
Proximity Threshold (mi.)	–	100	300	–	–
Utilities	123	75	91	64	85
Divested Utilities	44	35	41	41	41
R^2	0.280	0.293	0.262	0.248	0.261
Obs.	1953	1192	1447	1002	1350

D. Transmission & Distribution Net Investment ($ B)

	(1)	(2)	(3)	(4)	(5)
Post-Divest	0.043**	0.036	0.037*	0.036	0.032
	(0.021)	(0.026)	(0.022)	(0.022)	(0.021)
m nearest neighbors	–	–	–	1	5
Proximity Threshold (mi.)	–	100	300	–	–
Utilities	123	75	91	64	85
Divested Utilities	44	35	41	41	41
R^2	0.463	0.457	0.449	0.399	0.438
Obs.	1953	1192	1447	1002	1350

Note: The dependent variable is the year-to-year change in the capital stock reported in each respective category, in billions of dollars. Estimates in the first column are unweighted, while remaining columns are weighted by the indicated matching metric. All specifications include utility and year fixed effects. Standard errors clustered by utility in parentheses. * p<0.1, ** p<0.05, *** p<0.01

6 Conclusion

Restructuring the U.S. electricity sector has reduced generation costs, but does not appear to have lowered customer bills. Where did the surplus go? This paper suggests a way that regulated T&D utilities could have captured part of restructuring's savings with greater capital investments. Because restructuring left T&D regulation intact, local utilities were entitled to a return on their T&D assets in the form of a delivery charge added to restructured customers' bills. Cheaper energy, but higher delivery charges would offset one another in retail prices.

I find evidence consistent with this story in the annual filings of utilities to the Federal Energy Regulatory Commission. I match divestiture utilities who retained their regulated T&D operations with similar vertically-integrated IOUs whose states did not adopt restructuring legislation. Nine years after divestiture, I find T&D capital stocks were \$0.45B higher than predicted for the average utility whose generation assets had been divested. This amounts to 9.5% above counterfactual T&D assets.

It is possible that this excess investment makes up for long-delayed upgrades in traditional IOU systems, and is actually welfare-enhancing. On the other hand, the regulated electricity sector is widely known for its enthusiasm for capital projects (Averch and Johnson (1962); Cicala (2015b); Fowlie (2010)). Whether these investments were warranted or not, T&D utilities would be entitled to earn a rate of return on their rate base, and this excess capital would make its way into customers' delivery charges.

Beyond accounting for the effects of restructuring in the electricity sector, this paper provides insight into regulated utility behavior more broadly. Consistent with regulators' focus on nominal price increases, Hausman (2019) finds that fixed charges for retail natural gas are negatively correlated with marginal costs. A similar mechanism is at work here, suggesting upstream cost reductions may yield little benefit to consumers if a regulated utility stands between the input savings and end users.

These results suggest additional regulatory vigilance is required as renewable generation subsidies are expanded. While low-cost supply may depress prices in wholesale electricity markets, consumers will fail to benefit from (and make electrification decisions in response to) lower prices if regulated T&D utilities respond by expanding their rate base, effectively capitalizing the savings into a long-term flow of delivery charges.

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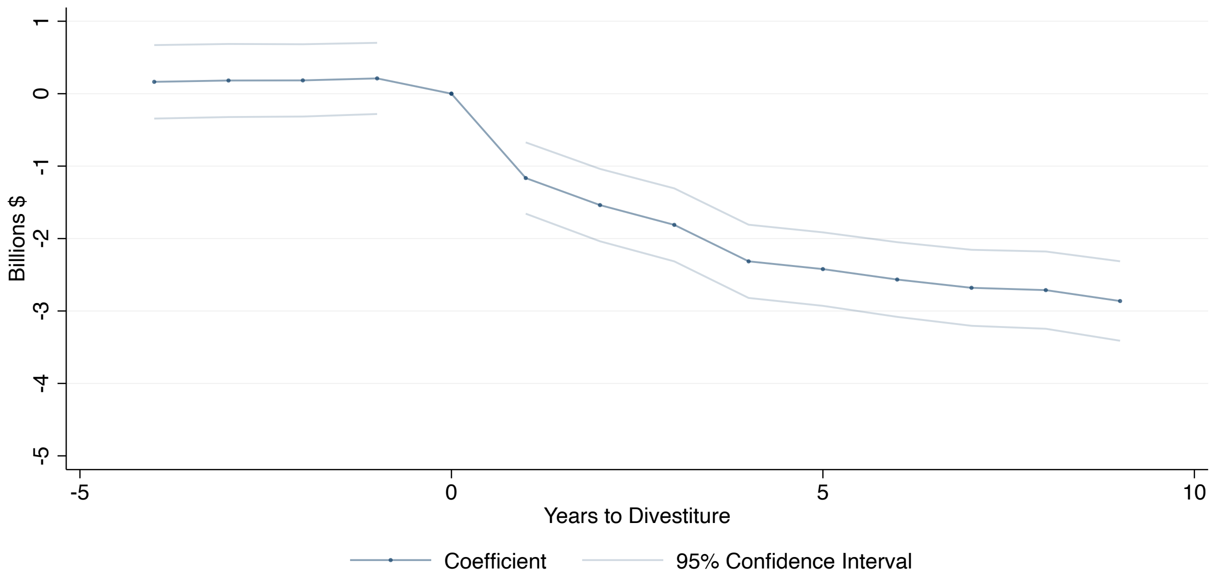
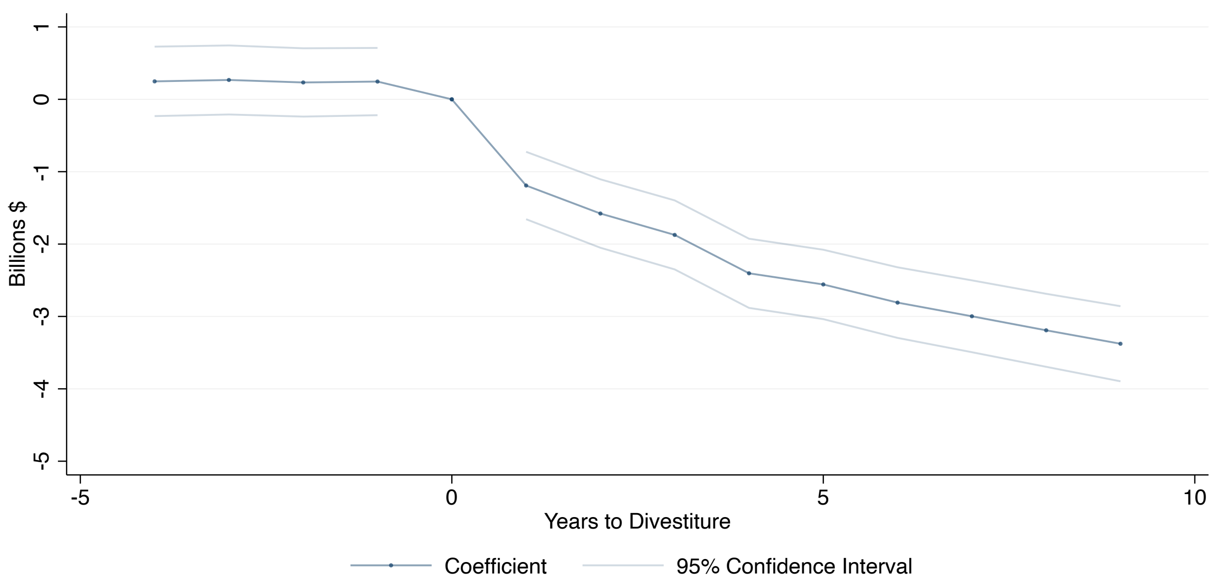
A Supplementary Results Appendix: For Online Publication

Figure A.1: Unmatched DD Estimates by Year to First Divestiture: Total and Production Capital

(A) Total Capital



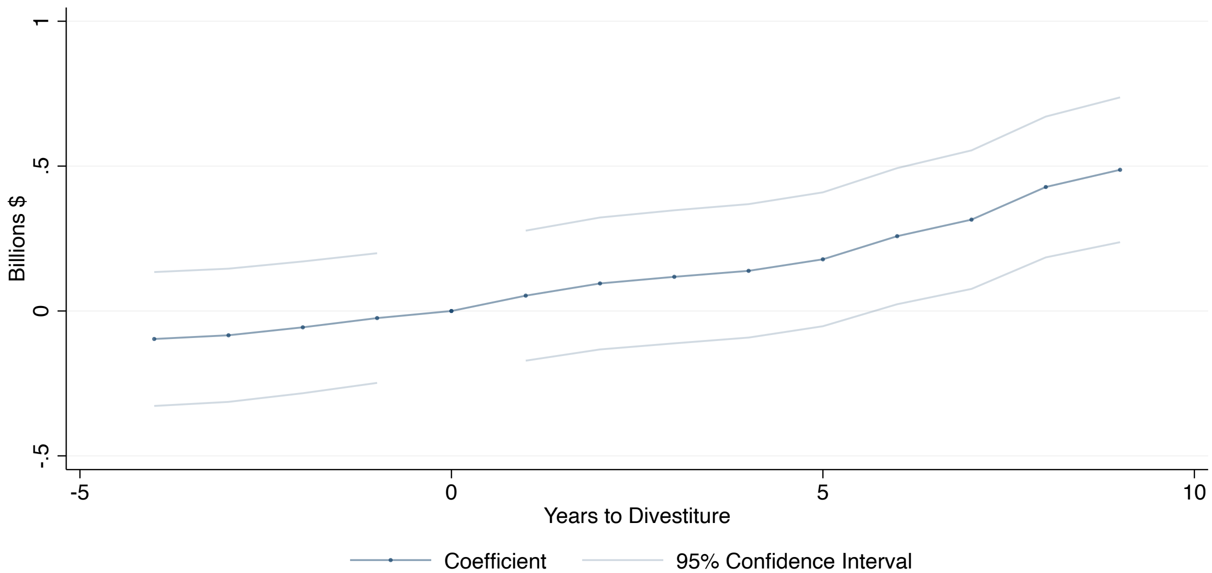
(B) Production Capital



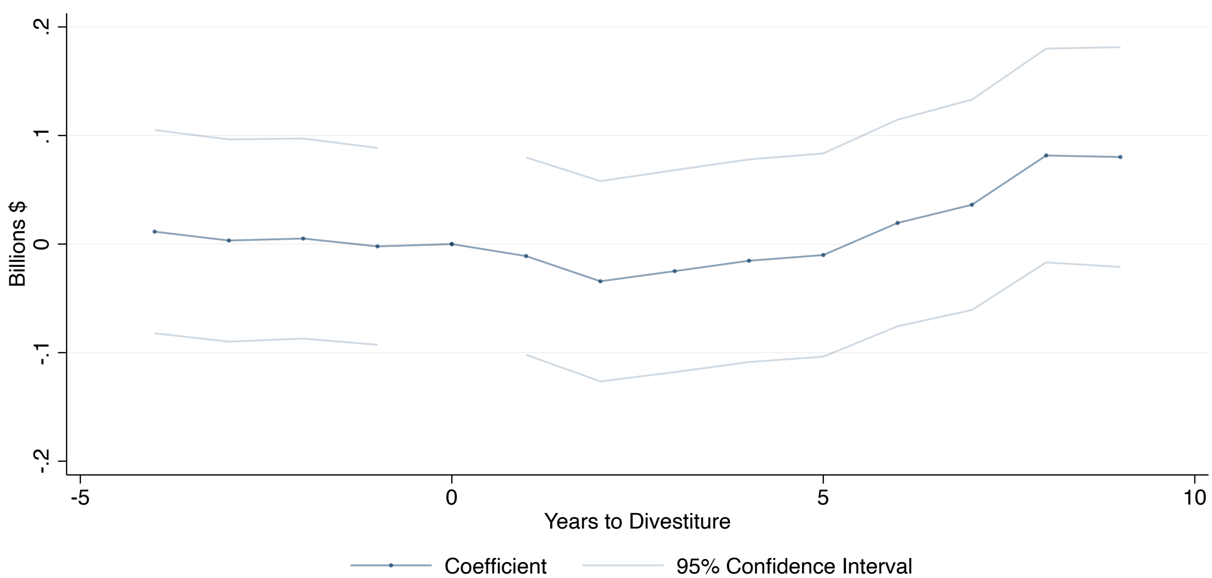
Note: These estimates are based on the complete, unweighted dataset without matching. Standard errors are clustered by utility.

Figure A.2: Unmatched DD Estimates by Year to First Divestiture: Distribution and Transmission Capital

(A) Distribution Capital



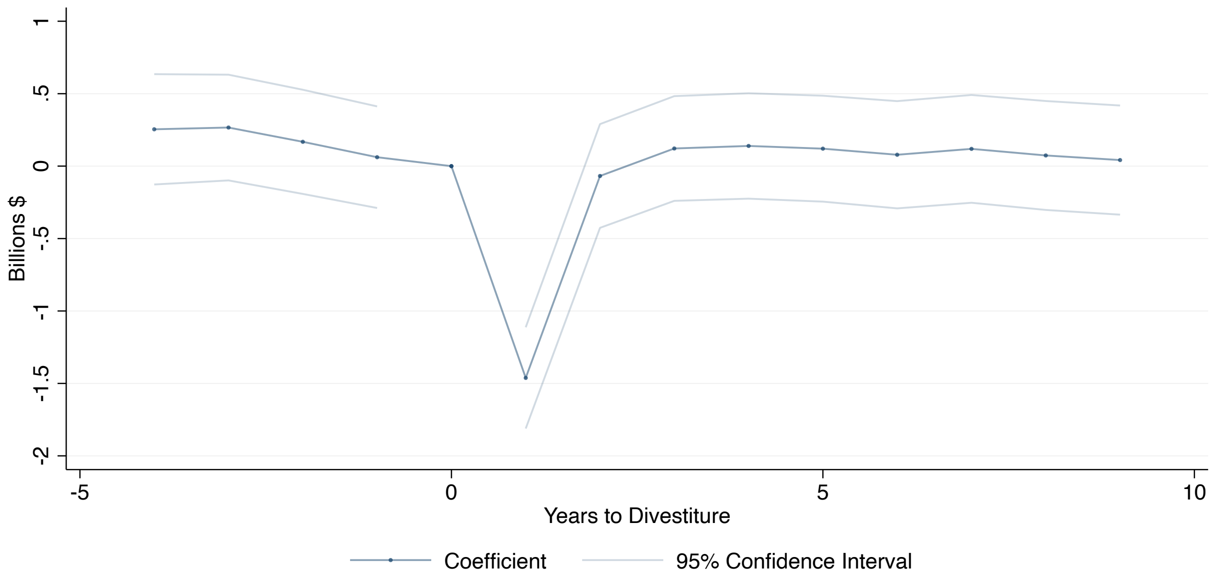
(B) Transmission Capital



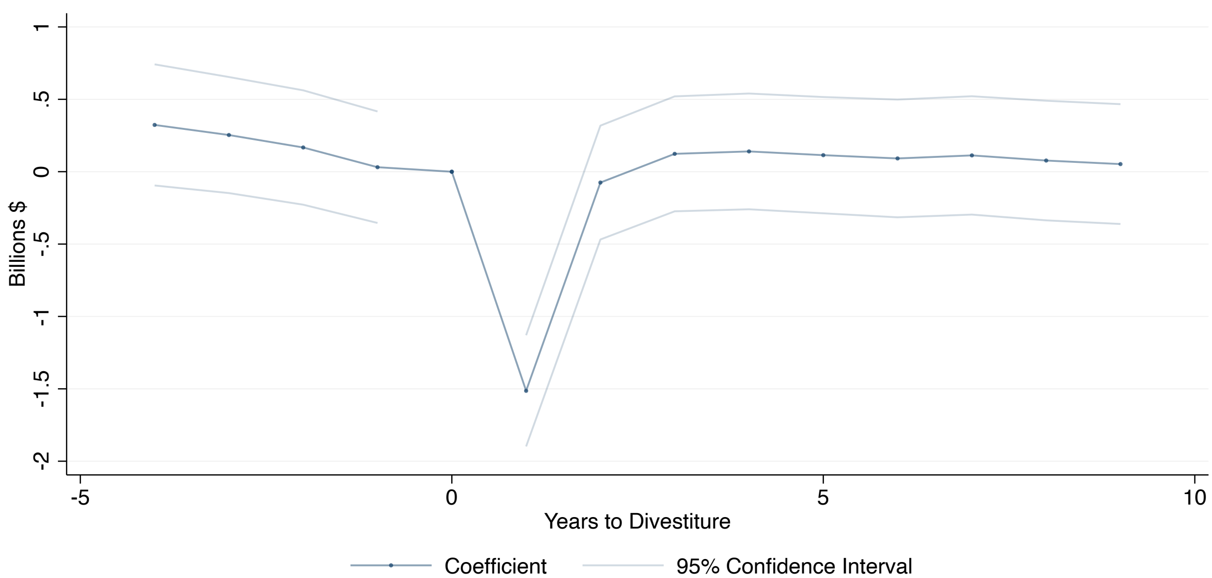
Note: These estimates are based on the complete, unweighted dataset without matching. Standard errors are clustered by utility.

Figure A.3: Matched DD Estimates by Year to First Divestiture: Total and Production Net Investment

(A) Production Net Investment



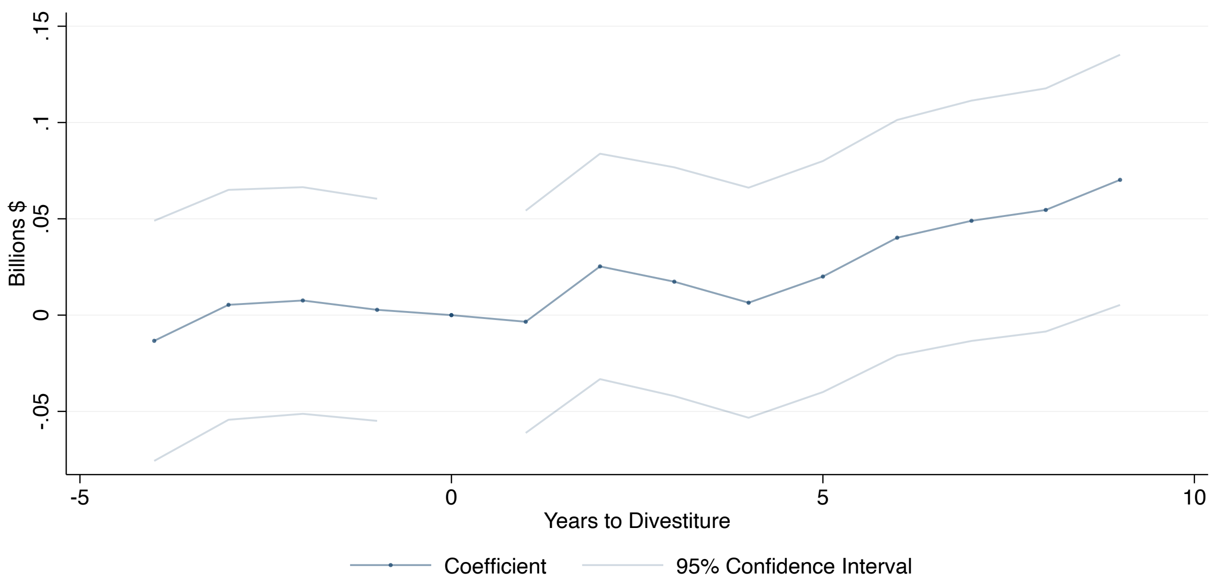
(B) Total Net Investment



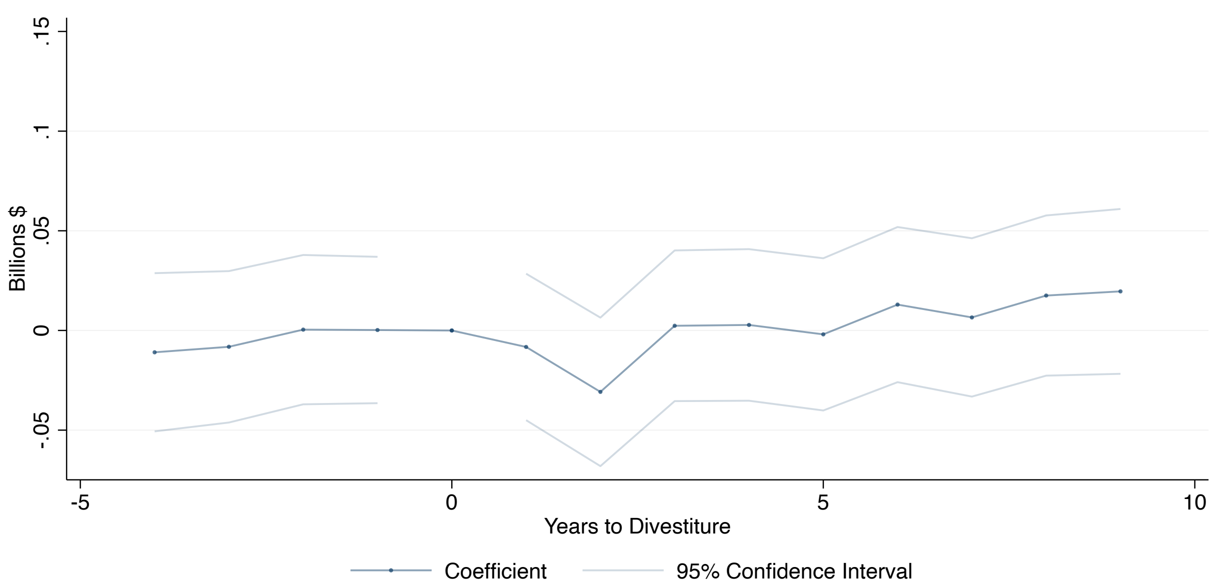
Note: Matching criterion: Nearest five utilities based on mean total capital stock between 1993 and 1997 and within 500 miles. Standard errors are clustered by utility.

Figure A.4: Matched DD Estimates by Year to First Divestiture: Distribution and Transmission Net Investment

(A) Distribution Net Investment



(B) Transmission Net Investment



Note: Matching criterion: Nearest five utilities based on mean total capital stock between 1993 and 1997 and within 500 miles. Standard errors are clustered by utility.