An Investigation of the Effects of Distributed Generation on Vertical Integration in the Wholesale Electricity Market

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Economics 829: The Economics of Institutions

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Fall 2025

Section I: Hypothesis and Data Sources

This paper aims to build on the literature studying the relationship between vertical integration, wholesale spot markets, and relationship-specific investments by examining empirically a set of related hypotheses about the relationship between vertical integration in the electric utility industry and the growing availability of distributed electric generation capacity enabled both by federal policy reforms and by sharp reductions since 2010 in the cost of small-scale photovoltaic solar installations and battery storage capacity. I hypothesize that as retail utilities expand their distributed generation capacity, all else equal,

1. Wholesale spot market volume will decline,
2. Vertical integration between retail utilities and wholesale utilities will decline, and
3. States that require net metering will see both of these effects to a lesser degree than states that allow retail utilities to purchase power from their consumers at below-retail rates.

For data on market structure, including vertical integration, spot markets, as well as data on distributed generation capacity and battery storage capacity, I have utilized data from the U.S. Energy Information Administration (EIA)'s Form EIA-860, Annual Electric Generator Report available at https://www.eia.gov/electricity/data/eia860/ and Form EIA-861, Annual Electric Power Industry Report, available at https://www.eia.gov/electricity/data/eia861/. For information on state net metering and feed-in tariffs, I used the DSIRE database maintained by the North Carolina Clean Energy Technology Center at N.C. State University, available at https://programs.dsireusa.org/system/program.

Section II: Background of the Analysis

Part 1. How Deregulations Between 1995 and 2002 Restructured the Electric Utilities Market to Allow Competition in Both Generation and Retail Distribution

From 1995-2002 a series of federal and state utility "restructuring" reforms legalized competition on both the generation side and the retail distribution side, when traditionally, for almost all of the 20th century, electricity was delivered by fully vertically integrated local monopolies whose retail prices were directly regulated by state governments. Beginning in 1995, the federal government and then state governments passed a series of legislative reforms allowing those integrated monopolies to disentangle and separately sell their generation and distribution assets. This allowed retailers without any generation capacity to purchase power at a fluctuating market price from generators (either on a long-term contract basis or in wholesale spot markets), with their rate of return, rather than the retail prices themselves, capped by state regulators.

Part 2. How Technological Innovations in Electric Generation Since the late-2010s Have Begun to Disrupt Firm Structure in Both Generation and Retail Distribution

A utility whose retail consumer base has distributed generation capacity is able to purchase energy from its own retail customers. These consumer-producers, many of whom are residential households, sell their excess capacity to their retailer when their private generation exceeds their private electricity consumption. The bulk of these consumer-producers use intermittent energy sources, especially photovoltaic solar panels and small wind turbines, and thus have excess energy to sell to their retail utility during periods of peak energy production when the sun shines or the wind blows. Photovoltaic generation capacity saw a sharp increase between 2010 and 2020 thanks to price reductions per kilowatt averaging 80-90% per year.

Because of the intermittent nature of these energy sources, they are often deployed alongside battery storage capacity, which, thanks to innovations in battery storage technology, has seen a precipitous decline in price and a consequent explosion in deployment by utilities and private consumer-producers alike. (For purposes of the present analysis, I do not consider the effect of battery storage capacity held by consumer-producers, but only by utilities themselves). There has also been a notable increase in distributed geothermal generation capacity, which though a renewable energy source, is not intermittent and is therefore considered part of a utility's "baseload" capacity for which battery storage is unnecessary.

Energy that a retail utility purchases from its consumers is a substitute for energy purchased on wholesale markets (either via long-term, fixed-price contracts with generating utilities or via fluctuating-price spot markets), or generated in-house. A retail utility whose customer base has a larger distributed generation capacity is thus less reliant upon wholesalers than one with a smaller distributed generation capacity. The works of Williamson (1983), Joskow (1987), Miller (1992), and Crocker and Masten (1996) suggest that retailers with relatively weak bargaining power in their relationship with their input supplier, are more likely to protect themselves against opportunistic pricing by a given supplier, or price volatility in wholesale spot markets, by seeking to merge (i.e. vertically integrate) with its input supplier than a retailer with relatively strong bargaining power vis-a-vis its input supplier.

The volume of distributed generation capacity available to that retailer is inversely related to that retailer's dependence upon the three traditional methods of acquiring wholesale electricity: and in-house generation. Generating electricity in-house protects a utility from price volatility on the wholesale electricity market, but exposes that utility to price volatility on the commodities markets for the various sources of combustible fuel used to generate electricity, especially natural gas and coal.

Part 3. The Exogenous Treatment - Policy or Technology?

To attempt to show some causality in the relationships I have described, I had intended to treat two federal policy changes as exogenous shocks, uninfluenced by preexisting market structure, which enabled the application of distributed generation and battery storage technologies to the wholesale market. The Federal Energy Regulatory Commission (FERC) issued a rule called Order 841 on February 15, 2018 allowing energy held in battery storage to be sold on wholesale spot markets. This had previously been prohibited. Similarly, on September 17, 2020, FERC issued Order 2222, (effective December 2018) which allowed power generated by distributed consumer-producers to be sold in wholesale spot markets, which likewise had previously been prohibited. These rules increased the supply of electricity available on the wholesale market and provided a new customer base to retailers with significant distributed generation in their network and to utilities with significant battery storage capacity for intermittent renewable energy sources. Prior to these orders, retailers could purchase power from consumer-producers and sell it back to those consumers at retail prices, but could not sell the power on wholesale markets, and wholesale-generators had no incentive to employ battery storage capacity unless they also directly served retail customers. After Order 2222, retailers with distributed consumer-producer customers but no in-house generation capacity, could now also sell their excess power on wholesale markets, reducing their incentive, I argue, to invest in their own in-house generation capacity. While Order 841, I argue, would likely increase spot market volume whereas Order 2222 would reduce spot market volume, both orders would likely reduce vertical integration.

To estimate the degree to which these FERC orders may serve as exogenous shocks to the market, I checked for whether the relevant dates surrounding the orders were accompanied by sharp changes in daily volume or price on the wholesale electricity spot markets. The EIA makes available granular data on the sales volume and price in wholesale electricity spot markets on the day-to-day level going back to 2001. Electric wholesale markets were legalized by FERC Order 888 in 1996, and did not begin to trade in significant volume until 2000, so the data available effectively covers the entire span of the post-restructuring electric market characterized by the availability of competitive, fluctuating-price wholesale spot markets. There are eight regional hubs where spot market trades take place, but prices tend to equilibrate across these hubs, so I ignore any differences between them. Not every day is a trading day, however, as the hubs average only 201 trading days per year. Between January 1, 2001 and December 31, 2024 there were 6,074 spot market trading days.

Out of those 6,074 days, three days in 2018 following FERC Order 841 stand out: February 20, 2018, three trading days after Order 841 was published, saw a 1470% increase in daily trading volume from the prior day, making it the 32nd-greatest daily volume change and placing it in the top 0.5% of daily changes in trading volume. Compliance filings for Order 841 were due in December 2018. November 26, 2018 saw the 31st-largest daily volume change, with an increase of 1642% from the prior day. These datapoints, though they do not hold constant any other factors that may affect the daily trade volumes on wholesale spot markets, would seem to reinforce the view that Order 841 substantially increased the incentive for wholesalers to utilize spot markets, thereby reducing, I would argue, their incentive to serve retail customers directly (i.e. to vertically integrate downstream).

Order 2222 went into effect 60 days after issuance, on November 16, 2020. Regional grid operators were then given another 270 days, until August 13, 2021, to submit compliance filings and propose their own implementation dates. Other minor parts of Order 2222 have compliance deadlines of February 1, 2027 and February 1, 2028, but I ignore these for the purpose of this analysis. Five trading dates between September 2020 and November 2020 saw sharp trading *decreases,* of between -71% and -82%, in daily trading volume, placing them among the 2.4% of largest trading decreases out of the 6,074 days observed (of which 2,773 saw declines in daily trading volume). Though less significant in magnitude and less concentrated on two specific dates, these cursory datapoints may similarly indicate the hypothesized reduction in demand for wholesale electricity on spot markets that the increased availability of distributed generation entails. That decline in demand is likely paired with an increase in supply on spot markets, however, and their combined effect would necessarily be reflected in lower prices. While wholesale prices rose from 2020 to 2021, this was likely due primarily to a sharp increase in the price of natural gas, North America's most common fuel source for electricity generation. Disentangling the effect on prices of the reduction in wholesale demand and increase in supply following FERC Order 2222 from all the myriad other factors that affect the price of the fuels combusted to produce electricity is well beyond the scope of this analysis.

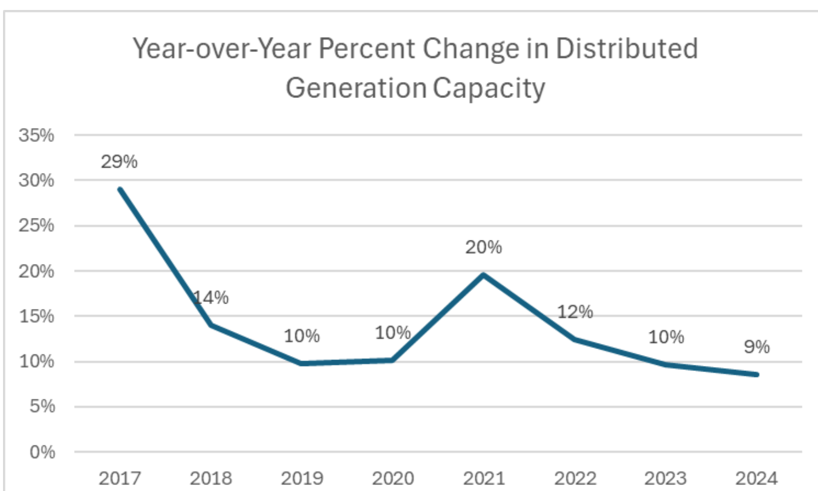

Figure 1.

Regardless, whatever its effect on the spot markets, Order 2222 was followed by a doubling of new national distributed generation capacity added, as shown in Figure 1. One might still, however, reasonably argue that Order 2222 merely codified what the industry already expected and did not itself have as important an effect on the amount of distributed generation capacity deployed as the price reductions in the technology of distributed generation, especially photovoltaic solar panels. This sharp decline in photovoltaic generation prices per kilowatt, thanks to innovations in the methods of their production, is the true exogenous treatment the effects of which this paper seeks to study. The timing of the FERC orders may provide merely a convenient approximation for the "tipping-point" at which distributed generation began to expand enough to affect utilities' incentives for vertical integration.

Part 4. Critical State Policy Differences:

Net metering is, in effect, a price control on wholesale power purchased by a retail utility from distributed, small-scale, part-time generators. It requires retail utilities to pay distributed producers the same rate to purchase a given wattage of power as it would cost that customer to purchase from the retailer. Net metering therefore prohibits a retail utility from conducting arbitrage across time by purchasing power at wholesale rates during times of surplus and selling it at retail prices during times of shortage. Retail rates are regulated by state public utilities commissions to charge customers a price equal to the average cost of delivering power to that retailer's consumers plus a maximum allowed rate of return, typically around 10%. This average cost includes the customer's share of the fixed cost of maintaining the retail distribution network plus the marginal cost of delivering the given amount of electricity to the given customer.

Some states, influenced perhaps by the political power of retail utilities that prefer not to have to face this price floor when compensating their customers for excess power fed into the grid, have enacted alternative price controls known as feed-in tariffs or net-billing, which come in a variety of forms, but tend to require utilities to pay distributed producers at least the marginal cost of delivering the same amount of electricity to their private meter. These alternative price floors allow retail utilities to purchase distributed power at below-retail rates, because while retail rates take into account the fixed cost of network infrastructure, feed-in tariffs allow retail utilities to ignore those fixed costs for purposes of compensating distributed producers. Still other states impose no price control whatsoever on what retail utilities must pay their customers for distributed power fed back into the grid. Whether facing feed-in tariffs or no price control at all, retail utilities possessing both battery storage capacity and distributed generation capacity among their customers may arbitrage across time by buying power from distributed producers at below-retail rates during periods of excess production and selling it at retail rates during periods of peak demand.

I hypothesize that states with net metering will see a smaller reduction in vertical integration than states that allow retail utilities to compensate consumer-producers at below-retail rates, either by charging lower controlled prices or by exercising monopsony power to compensate distributed producers at a rate even below the marginal cost of delivering that amount of power.

Section III: The Tests

Part 1. National-level Regressions

First Test: Spot Market Volume as a Function of Distributed Generation Capacity.

As measures of wholesale spot market volume I considered testing the volume in megawatt-hours (MWh) sold per year, the volume sold per year in dollar terms, the average number of trades per day, the average volume in MWh per day, the average volume sold in dollars per day. However, each of these measures is a function not only of the relative importance of spot markets compared with the other means of acquiring electricity wholesale, including long-term contracts and in-house generation, but also of the overall size of the retail market, which is a function of the amount of consumer demand. To use these measures, I would thus have to hold constant the amount of consumer demand, which is not relevant to the question I wish to study. To get around this problem, I determined that the best measure of spot market volume is annual spot market sales as a percentage of total retail sales. This measures the *relative* importance of spot market sales to other means of acquiring electricity wholesale, including long-term contracts and in-house generation, without being influenced by the overall size of the retail market. (I define long-term contracts as those longer than four days, because the spot markets involve transactions that take up to four days to execute). This spot trade measure (spot trade volume as a percent of retail volume) ignores shifts between wholesale contracting and vertical integration. While the number of active trading hubs increased from five in 2001 to eight in 2014, change in the total trading volume is primarily along the intensive margin, in number of trades per hub, rather than the extensive margin of adding more hubs.

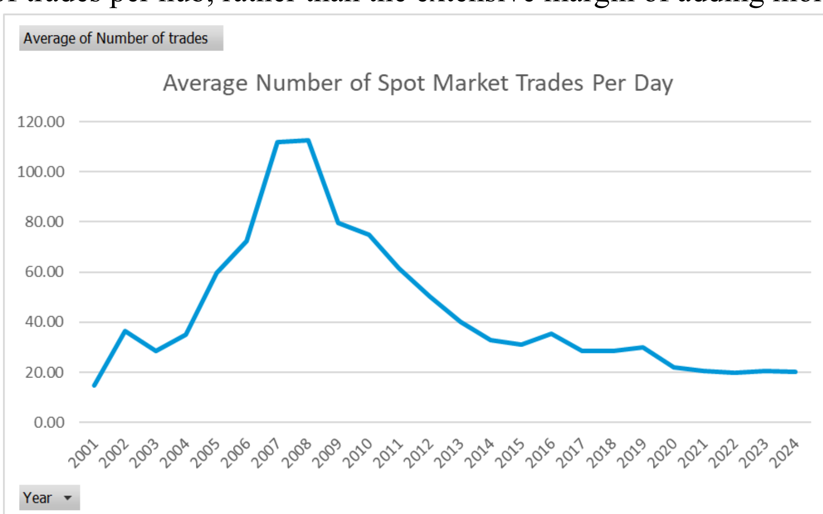

Figure 2

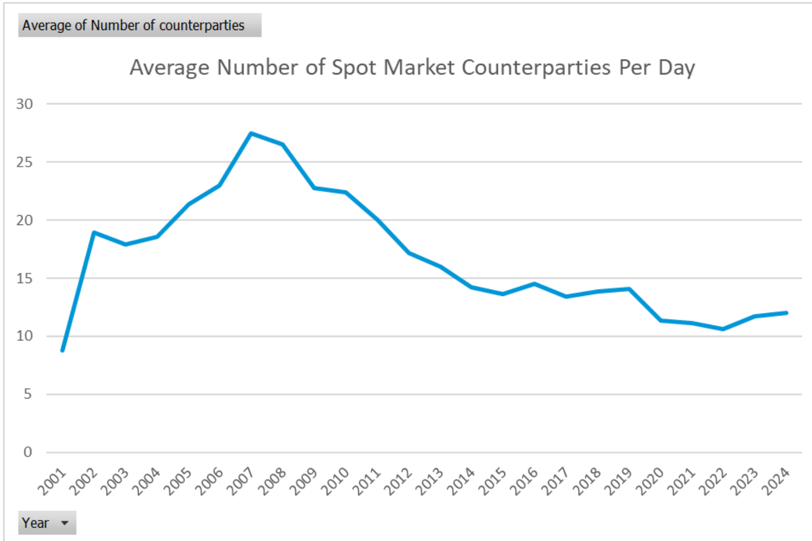

Figure 3

I hypothesize a negative correlation between this measure of spot market volume and the U.S. aggregate distributed generation capacity between 2010, when the EIA began to record distributed generation capacity, battery capacity, and net metering volume, and 2024. As shown in Figure 4 below, I was very successfully able to reject the null hypothesis that there is no relationship between distributed generation capacity and spot market volume. I found a negative correlation between distributed generation capacity and wholesale spot market volume (as a share of total retail volume), with a strong goodness-of-fit ($R^2 = 0.75$). This unsurprisingly confirms the intuition that as retailers can purchase more of their power from their own consumers, they will purchase less on the wholesale market.

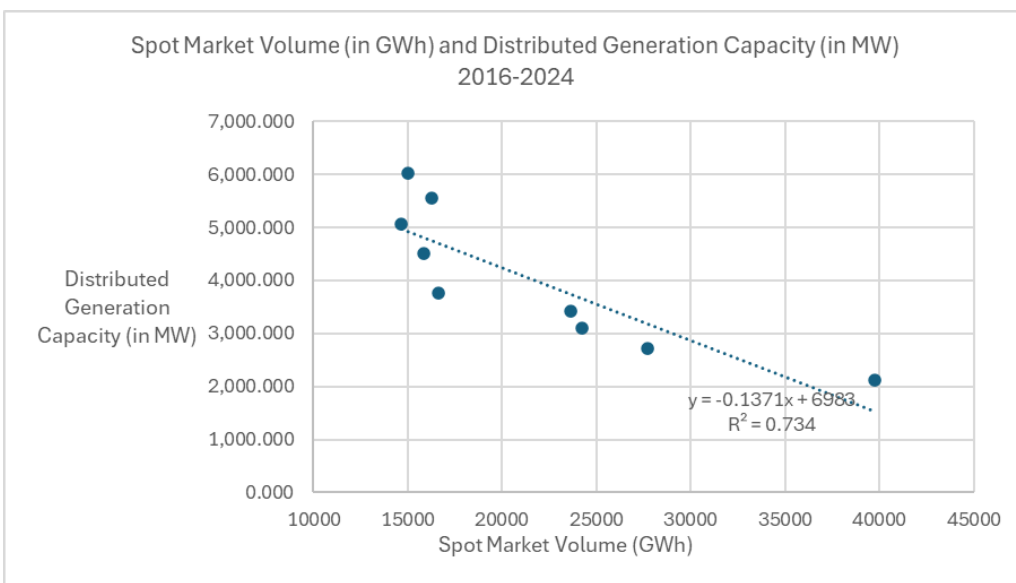

Figure 4

These findings provide a preliminary indication of the research hypotheses articulated above, that as distributed generation comes online spot trade volumes tend to fall. When considering the direction of causality in this relationship, if any, it should be obvious that the volume of spot trades could not cause the technological innovations or policy changes that have made distributed generation and battery storage cost efficient for so many households and utilities to install. We cannot, however, ignore the possibility that this observed correlation exists because of a third variable effect upon both measures.

Second Test: Vertical Integration as a Function of Distributed Generation Capacity

As a measure of vertical integration between retail utilities and wholesale utilities I use annual retail revenue earned by "full-service" utilities, (these are traditional vertically integrated utilities that both own in-house generation capacity and directly serve retail customers), as a percentage of total retail revenue. I also use annual electricity volume (in MWh) sold by full-service utilities as a percentage of total retail electricity volume sold. Just as described above, these measures of vertically integrated sales as a percent of all retail sales avoid the problem that would result from using various absolute measures of vertically integrated sales, namely that those quantities are a product of consumer demand, not of market structure alone. I hypothesize a negative correlation, significant at the 95% confidence level, between this measure of vertical integration and the U.S. aggregate battery storage capacity and distributed generation capacity.

I had alternatively considered using the number of utility mergers as the most direct measure of vertical integration, given that it would be possible to label each firm participating in a merger as a retailer, a generator-wholesaler, or a vertically integrated firm, however, I encountered an insurmountable data limitation. Most utilities are not IOUs. However, the only form of utility that may be privately owned and sold is an IOU. As non-profit entities, electric co-operatives are not legally property and may not be bought or sold *in toto*. Rather, their infrastructure may be purchased by other entities and the cooperative's legal status as a corporate entity ceases to exist. The EIA therefore only counts as "mergers" the sale of IOUs, which provides a very incomplete picture of the market. Also, while vertical integration may take the form of a merger between a generating utility and a retail utility, another, perhaps more common form of vertical integration is simply when a retailer decides to invest in adding in-house generation capacity, or a wholesale-generator decides to begin marketing directly to retail customers. These forms of vertical integration would not be captured by the mergers measure. It should also be noted that in a handful of cases, a utility of a given type has legally restructured into another type, but this is uncommon enough to ignore for purposes of this analysis.

I was able to reject the null hypothesis that there is no relationship between vertical integration and distributed generation capacity. As a measure of vertical integration I used the percentage of utilities categorized as "full service" utilities, with both generation capacity and retail customers. The share of utilities that are vertically integrated and the amount in MW of distributed generation capacity are negatively correlated with a moderate goodness-of-fit (R^2 = 0.35).

I also compared distributed generation capacity with the percent of utilities with in-house utility-scale generation capacity. This negative correlation, seen in Figure 5 below, shows, more than any other indicator, the clear tradeoff retail utilities face between investing in generation capacity (or merging with a utility with generation capacity) and purchasing wholesale power from distributed consumer-producers. The accuracy of this model is affected by one outlier year, 2019, which was characterized by an unusually low percentage of utilities with generation capacity thanks to an unusual spike in the number of operating retail-only utilities. The large increase in the number of operating retail utilities in 2019 may have continued unabated if not for the sharp economic contraction of 2020 which caused a steep 49% reduction in the number of operating utilities.

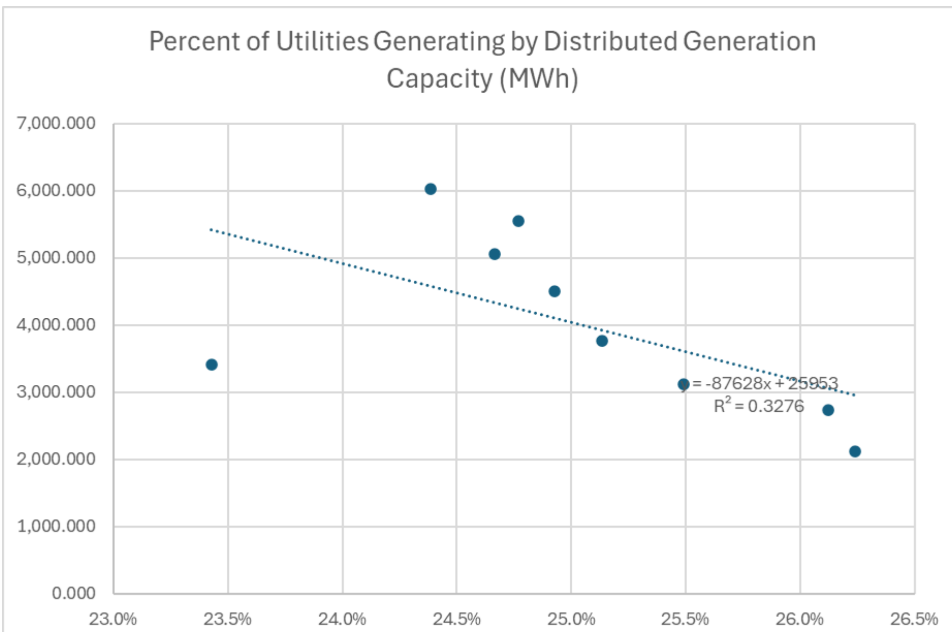

Figure 5

Comparing the percent of utilities with in-house generating capacity against distributed generation capacity I observed the hypothesized relationship, a negative correlation with an R^2 of 0.33 between distributed generating capacity and the number of utilities with in-house generating capacity, which are input substitutes. (This measure is not a proxy for vertical integration, because many generators have no retail customers).

I also compared the revenue earned by full service utilities with generation capacity, however, and found a positive correlation, with an R^2 of 0.17, between those measures. For battery capacity it is 0.2. This indicates that while the rise of distributed capacity has seen a decline in vertically integrated firms, those that remain collectively earn a larger share of total revenue than they did when generating capacity was low.

I compared distributed generation capacity (in Megawatts) with the number of utilities categorized as "full service," meaning they are vertically integrated firms that serve retail customers and own in-house generation capacity.

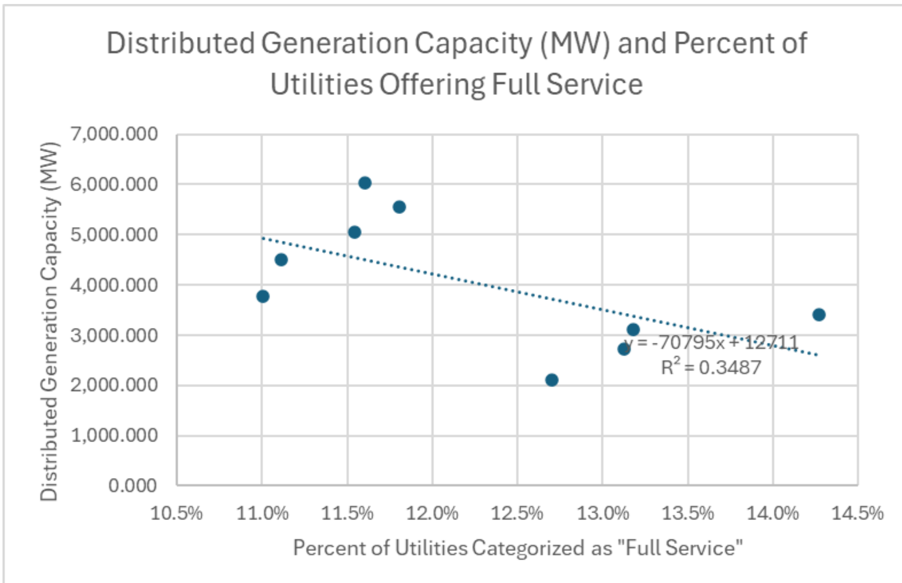

Figure 6

These findings reinforce my research hypothesis that distributed generation has coincided with a reduction in vertical integration. If this correlation reflects a causal relationship, then it likely runs in the direction of distributed generation capacity influencing the number of utilities with in-house generation capacity, as a retail utility with battery storage capacity and a strong base of distributed generation capacity may choose to forego investing in utility-scale generation capacity to meet periods of peak demand given that it has a ready alternative source of generation already available. One could, however, advance a plausible argument that

These findings, coupled with the earlier findings on spot market volume, indicate that the rise in distributed capacity has coincided with a reduction in the use of both wholesale spot markets and vertical integration and that the reduction in spot markets is greater, (presumably because the demand for wholesale power on spot markets is obviously much more price-elastic in the short run than the demand for in-house generation capacity, which requires complex and site-specific capital investment).

Part 2: State Analysis

Admittedly, state net metering or feed-in tariff policy cannot truly be considered exogenous to firm structure, because a state's decision to enact, maintain, or overturn net metering is certainly a function of the political influence, and financial resources, of the owners of distributed generation capacity and of the retailers to whom those distributed generators sell their excess capacity. Nevertheless, I found it instructive to test for a relationship. It should be noted that some local governments have required net metering where it is not required by the state, and some utilities have voluntarily adopted the practice, but I ignore these for the purpose of my interstate analysis.

Twenty-three states and DC required net metering for the entire period studied: 2001-2024. As of the end of 2024, 43 states and DC had net metering alone. Three had a hybrid policy. Of those state net metering policies enacted after 2000, the average age was 17 years. Five states had no net metering 2001-2024: Alabama, Idaho, South Dakota, Tennessee, Texas. States with a hybrid policy 2015-24: California, Minnesota, Washington. All three had required net metering during the entire 2001-2014 period.

I gave each state in each year a score, between 1 and 5, to measure the amount of monopsony pricing power that retail utilities in that state may legally exercise when purchasing power from their consumers in that year. A score of 1 denotes the absence of any price control regulating retail utilities' compensation of distributed generators for the entire 15-year period from 2010 to 2024. A score of 5 denotes mandatory net metering. A score of 3 represents the presence of a mandatory marginal cost feed-in tariff. A score of 4 denotes hybrid policy that allows feed-in tariffs for some forms of distributed power, but requires net metering for others. A score of 2 would denote a hybrid policy that allows a feed-in tariff for some forms of energy and no price control for others (however, this is an empty set, as no states met this definition). Connecticut had the unique situation until 2021 in which it required net metering for only residential consumer-producers and applied no price control to non-residential consumer-producers; I coded this as a 3; admittedly, that is a very arbitrary designation. I then summed each state's scores over the 15-year period studied to get a measure that represents the amount of market power retail utilities may exert in their transactions with distributed generators.

The state retail market power scores generated are as follows:

State	Market Power Score	Category
AL	15	Strong
ID	15	Strong
SD	15	Strong
TN	15	Strong
TX	15	Strong
MT	23	Strong
CT	51	Strong
MI	55	Strong
MS	55	Strong
CA	65	Weak
MN	65	Weak
WA	65	Weak
All Other States:	75	Weak

Table 1

In 2015, three states with net metering (California, Minnesota, and Washington) created new feed-in tariffs for some customers while maintaining net metering for others. This can explain why the national rate of growth of new net metering customers fell sharply in 2016 and 2017, as shown in Figure 9. That rate of growth leveled out in 2018, the year of FERC Order 841, and begins to grow again in 2020, the year of FERC Order 2222. This makes sense given that those two orders gave retail utilities a greater incentive to offer discounts, financing, and other incentives to their customers to install private generation capacity.

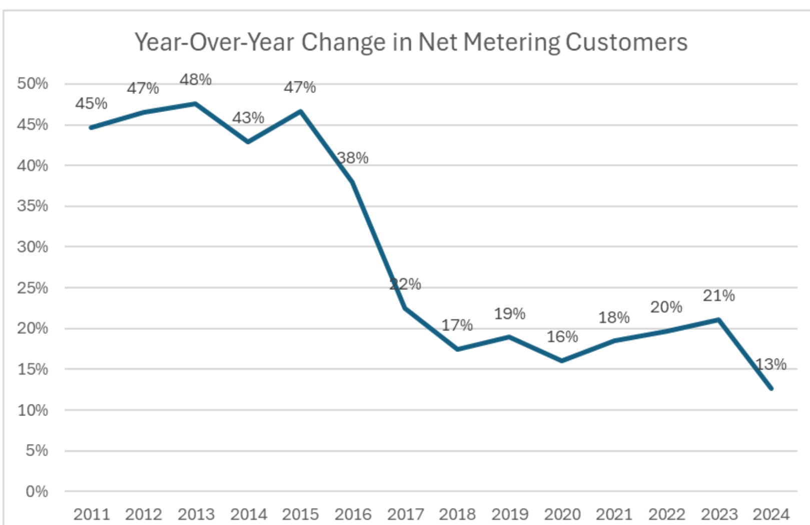

Figure 9

Table 2 shows that retail utilities in the states without price floors for compensating distributed generators unsurprisingly tend to earn much higher annual retail revenues than those in states with mandatory net metering. States with a hybrid policy are excluded for simplicity.

Average Total Annual Utility Revenue in the States (including DC):

Policy	**Number of States**	**Average Annual Utility Revenue**
No price floor for distributed generators for the entire 2001-2024 period:	5	$642,992,412
Enacted net metering some time between 2001 and 2024	17	$213,735,621
Required net metering during the entire 2001 - 2024 period	24	$236,270,278

Table 2

To test my hypothesis that the decline in vertical integration will be more significant in states with strong retailer monopsony power (those without net metering) than in states with net metering magnitude, I regress the national average retailer market power score per year against the vertically integrated ("full service") and data used in the national regressions above. I treat the retailer monopsony power score, which is the result of state policy, as an exogenous independent variable in the regressions against the average market share (by sales volume) of vertically integrated utilities.

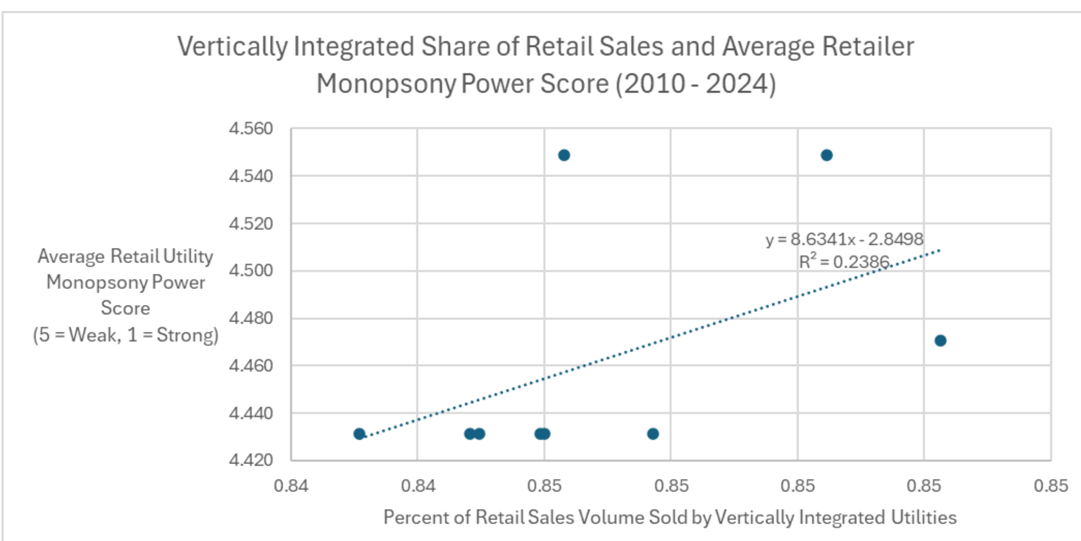

Figure 10

Regressing the national average retailer market power score against the percent of retail sales volume (in MWh) sold by vertically integrated ("full service") utilities reveals a positive correlation, albeit with a weak goodness-of-fit of $R^2 = 0.24$, between the weakness of retailer monopsony power (i.e. the number of years with mandatory net metering) and the percent of sales made by vertically integrated firms, as shown in Figure 10. This provides a modest justification of the hypothesis that states with weaker retailer monopsony power will see a smaller decline in vertical integration than states with stronger retailer monopsony power.

Section IV: Conclusions and Limitations of the Results

This study has attempted to merely show the correlations hypothesized above. Having established these correlations, we must then consider whether a causal relationship exists between the measures listed above, and if so, in which direction causality runs. To hypothesize the direction of causality, we must rely upon intuition guided by theory.

While it may be safe to assume that the technological innovations that have dramatically reduced the price of battery storage and photovoltaic solar generation are likely exogenous to market structure in the U.S. electricity market, the *quantity* of distributed generation and battery storage supplied is probably not truly exogenous to market structure. That quantity is largely the result of incentives in the federal tax code and state tax codes, which is itself largely a function of the political desire to displace fossil fuels by subsidizing renewable energy, which is in turn a function of the political weight placed upon climate change relative to other issues of concern to voters. To the extent that tax incentives and subsidies are determined by these considerations, they are not likely endogenous to firm structure in the utility market. However, these tax incentives for deploying distributed generation capacity and battery storage are also, to some extent, the result of lobbying by electric utilities, which lobbying is financed by profits in that market, which profits are in turn a function of state rate-of-return regulations and of firm structure. It is thus very difficult to disentangle the extent to which the aggregate amount of distributed generation and battery storage capacity in the United States, or in any given state, is a function of firm structure, and the extent to which it is a function of factors unrelated to firm structure.

Thus, while I believe I advance here a plausible and intuitive theoretical argument that distributed generation capacity resulting from technological innovations and tax incentives unrelated to firm structure encourages wholesale and retail utilities to vertically separate from one another, I cannot rule out the possibility of causation running reverse to that which I hypothesize. Namely, it could also be plausibly advanced that when utilities find their revenue-maximizing degree of vertical integration, this increases their market rate of return, which (though capped by state rate-of-return regulation), still makes available more resources for lobbying policymakers to enact policies that alter the incentives to deploy distributed generation and battery storage capacity. These policies include direct tax deductions or credits for installing distributed generation and battery storage capacity, but may also include trade policies that change the quantity of solar panels and electric batteries that may legally be imported, or that change policy toward mining or importing rare earth minerals and other inputs into electric batteries and solar panels.

Likely, causation runs in both directions, but at different magnitudes. In further research, it may be worthwhile to test a plausible hypothesis that distributed generation capacity is a much stronger determinant of vertical integration than vertical integration is of distributed generation capacity.

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